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Value Proposition of Battery Energy Storage Systems on Electric Distribution Systems in Regulated Environments

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VALUE PROPOSITION OF BATTERY ENERGY STORAGE SYSTEMS ON ELECTRIC DISTRIBUTION SYSTEMS IN REGULATED ENVIRONMENTS

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ABSTRACT

The electric power grid will be facing new challenges in the coming years. One recent trend has been more efficient electrical devices throughout the world, stagnating load growth. In addition, the historic model of generating electric power using slow, large, centralized power plants is beginning to disappear as distributed generation (DG) becomes cheaper and more accessible, both to power utility companies and customers. The combination of these two changes results in a changing load profile that is difficult for traditional generation sources to follow. Finally, the growth of electric vehicles (EVs) will continue to exacerbate this issue.

On the distribution level, these shifts in load profiles result in accelerated equipment aging and equipment upgrade requirements. In order to reduce equipment costs, this thesis surveys 4 distribution feeders from a local southeast utility, forecasting changes possible in the next five years, and calculates the value proposition of using battery energy storage systems (BESS) to mitigate issues caused by the changing demand load profiles. Siemens PTI's PSS SINCAL's functionality to achieve this goal is reviewed.

It was found that some distribution feeders have high capacity equipment that would not require any modifications to withstand significant future changes. For the one feeder that does, a BESS had a lower value proposition than upgrading overloaded distribution equipment when using approximate equipment costs.

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CHAPTER 1: INTRODUCTION

Background

Electric demand growth has consistently grown over time since around the 1950s up until around 2007 [1]. Utility operations and planning have dealt with this growth in a consistent manner: adding new generation plants to serve the higher peaks and upgrading distribution equipment where necessary to ensure power is reliably delivered. New technologies in the 21st century are changing electric demand growth and open the door to new solutions for the new problems the grid faces.

Energy storage has been used in the U.S. grid for years. The primary function has been to reduce the need for new power plants by storing energy during daily demand valleys and releasing this energy during peak demand hours. However, distributed energy resources (DERs) such as photovoltaic (PV) generation and wind generation have created new problems that centralized energy storage cannot solve. Advances in battery technologies, both in function and in price, have led some utilities to consider using distributed energy storage to solve these new distributed problems.

Aims and Objectives

A research project was created to investigate the effects of PV and EV growth on several example distribution feeders part of Duke Energy's network, a power utility that serves several areas in the U.S. One aim of the project is to determine the value proposition of integrating energy storage (ES) into distribution feeders to reduce system vulnerabilities that arise as a result of increased PV penetration and EV infrastructure growth. Another aim is to create a roadmap for utilities to follow in order to estimate the value proposition of integrating ES on their own distribution feeders. Thus, the overall goal for the project is both the results of the studies and the documentation of the process of performing these studies.

Studies performed and to be performed for the project include hosting capacity analysis, dynamic response studies, and real-time analysis. To perform these studies, Siemens PTI's PSS SINCAL tool was selected as the primary software. It contains several useful modules including a hosting capacity tool, file conversion tools, and works with a related dynamic modeling tool called PSS NETOMAC.

For this thesis, the process of determining the need and the value proposition of energy storage on four feeders from Duke Energy is analyzed. A customized BESS model was developed to maximize the value proposition on these specific feeders for the application of energy arbitrage. Comparisons between upgrade costs of distribution equipment and new battery installations are made. Finally, a recommendation is made for the most financially viable option for mitigation of system vulnerabilities.

Contribution to Knowledge

This thesis describes a process to determine the best value of integrating ES on a distribution network in a regulated environment. The goal is for this process to be repeatable for any distribution system that may be examined for ES integration. In addition, this thesis details the methods and tools used with PSS SINCAL to perform certain studies.

Layout of the Thesis

The following chapters make up the remainder of this thesis:

Chapter 2 introduces the problems facing the grid today and in the future that form the basis of the motivation behind the thesis. These problems are mostly related to PV penetration and EV infrastructure growth.

Chapter 3 discusses current BESS technologies and applications designed to mitigate the problems showcased in the previous chapter and details the calculation of the economic value of BESS on distribution systems.

Chapter 4 details the case study performed to calculate ES value on several distribution feeders. In this section, the distribution feeders themselves and the steps taken to adapt the model for use in PSS SINCAL are reviewed. Each step of this process is documented with the goal of making this process easily replicable.

Chapter 5 reviews the results of the studies and determines the best option for each.

Chapter 6 summarizes the key points of the thesis and highlights possible future studies based on the results discussed. Considerations are made for studies not performed in this thesis that could alter the results.

CHAPTER 2: THE EVOLVING GRID

Introduction

Historically in the southeast U.S., the overall daily electric demand profile varies between a daily single peaking summer profile and a daily dual peaking winter profile [2]. Generation sources have traditionally been large and centralized power plants split into two types: baseload and load following. Relatively large and slow ramping generation sources such as nuclear and coal make up the baseload generation as they are unable to ramp quickly enough to follow the daily load curves while small and fast ramping generation sources such as natural gas and hydropower make up load following units.

Since around 2007, U.S. electric demand has mostly flattened [1]. Much of this can be attributed to more efficient electrical devices and more efficient industrial processes. Although population growth has continued to increase electric demand, current forecasts estimate load growth will continue at a rate of only about 1% per year [3]. On top of this low growth, changes in the grid have drastically affected load behavior, or what demand appears to be from a generation perspective. These changes, especially in PV systems and EV infrastructure, are forecasted to become more pronounced in the years to come, creating new problems and requiring new solutions for the grid.

PV Systems on Distribution Circuits

Growth Estimate

Solar installations throughout the U.S. continue to grow. Studies by several national laboratories point to explosive PV growth from the early 2010s as evidence that PV penetration will continue to increase [4]. However, a large part of PV penetration is due to utility-scale PV, especially in the studied area of the country. Estimation of distribution-level PV installations is difficult. This is primarily because residential customers may not notify a utility that they have installed a PV system. Reference [4] presents annual U.S. PV demand projections up to the year 2022. The graph on page 37 of this report shows predicted PV installations by year. Residential installations per year will slightly increase in the future based on current trends.

Bulk Power System Impacts

Grid system operations has been relatively consistent throughout much of the life of the modern grid. As presented before, generation has been large, centralized, and is ultimately designed to match electric demand. Distributed energy resources (DERs), especially renewable energy sources like wind and solar, are changing that notion. These generation sources are designed to output maximum power whenever possible, even when the power, from an operations perspective, may not be needed. Laws such as the Public Utility Regulatory Policies Act (PURPA) requires electric utilities to 1) allow third party companies to construct and connect generation plants on their system, and 2) purchase power from these independent power producers (IPPs) at the price that the utility would have otherwise had to pay to generate this power, referred to as the “avoided cost.” This act has now been used in states to force utilities to allow generation from unreliable sources such as renewable generation. Economics aside, this has resulted in a variety of difficult questions for system operators to answer daily [5].

California currently contains more PV capacity than any other state in the U.S. System operators there have experienced the effects of PV systems on their grid. One specific phenomenon is the “duck curve” [6]. During the middle hours of the day, electric demand is traditionally reduced. Plotting electric generation in a time series format shows this decrease as a valley during the middle hours of the day, such as the one in figure 2.1. PV systems, as they are distributed and do not follow load, appear to operations departments as “negative” load, meaning they reduce the apparent demand during generation. A high amount of PV generation takes place during the middle of the day, specifically during the time when load demand falls into the valley explained above. California ISO has nicknamed this phenomenon the duck curve due to the generation shape resembling a duck and summarizes its effects into three specific issues relating to system reliability.

First, the times during which PV generation increases and decreases takes place directly when load decreases and increases, respectively. This causes dramatic ramps in electric demand. As PV penetration increases, the steepness of these ramps also increases, and traditional generation sources become less able to match supply and demand because of their physical ramp rate limitation. One possible solution is to reduce, or curtail, PV generation. With much PV generation coming from IPPs protected by PURPA, utilities cannot routinely use this solution.

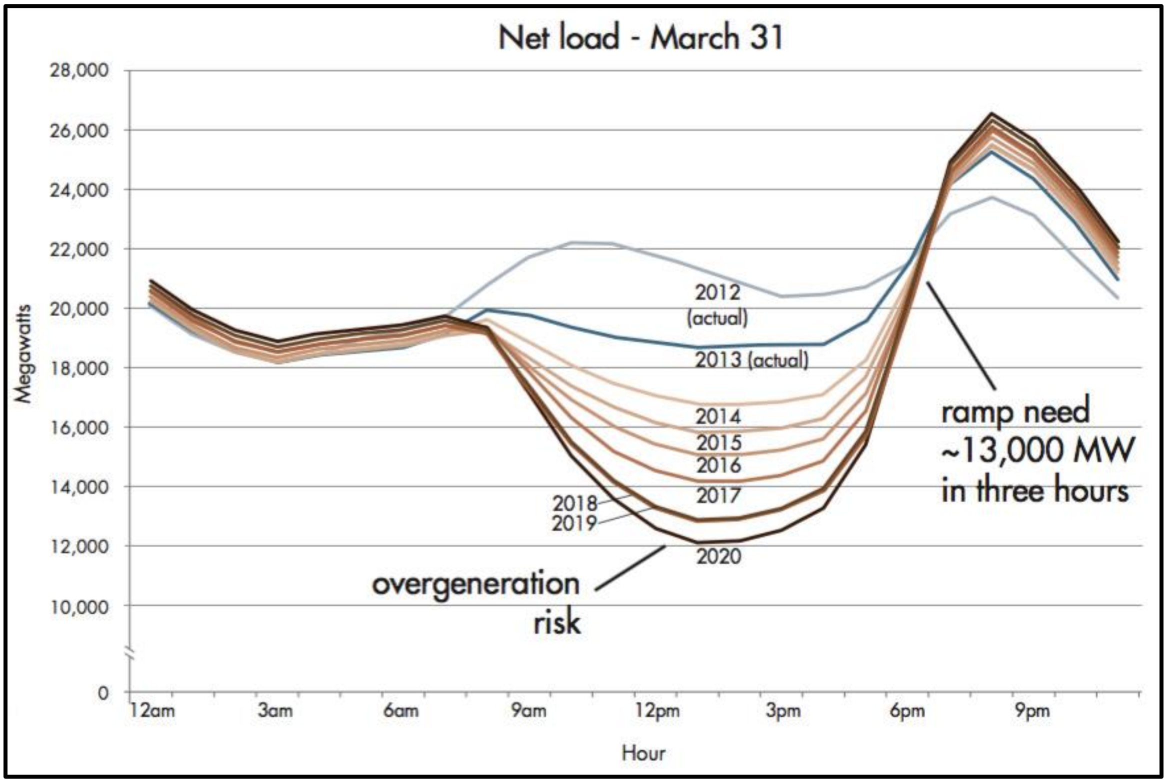

Figure 2.1: A comparison graph of California ISO's required generation given future estimated PV penetration levels.

The next duck curve effect is overgeneration risk. When PV generation is high and electric demand is low in the middle of a day, it is possible that shutting off all load-following generation will still cause net generation to be larger than net electric demand. Electrically, this problem is solved by a utility exporting power to a different utility that may have lower PV generation and could use the excess power. As PV penetration increases across the country, it may no longer be possible to export this power. In the future utilities may need to curtail large, slow baseload generation during the middle of the day. This may reach a point where the ramp rate required is too steep for these large generation sources to track and will require new solutions for power management.

The final duck curve effect described by California ISO is decreased frequency response. PV generation has no physical moving parts, and as a result does not have the ability to provide frequency support to the grid in the form of inertia. During the middle of the day when traditional generation must be ramped down for PV generation, there is less inertia available from the reduced total spinning generation remaining. Not only is there less inertia to respond to sudden grid load or generation changes, but as PV generation may be drastically variable on a cloudy day, there is a greater risk that a dramatic change in generation may require inertia for system reliability.

Distribution Line Effects

While the previous section has detailed bulk power system effects, there several effects PV systems may have on medium- and low-voltage distribution networks. The first effect is harmonic content generation. IEEE 519 recommends that total harmonic distortion (THD) and total demand distortion (TDD) of voltage and current provided to a customer be restricted to a certain level. PV systems provide power to the grid through an inverter which produce significant harmonic content due to their design. Although output filters remove much of the harmonic content of the output, harmonic distortion still exists. As PV penetration increases, localized harmonic distortion may increase on a distribution line and push THD and TDD outside acceptable limits. This could result in a variety of effects, many of which include damage to equipment and can cost the utility more than preventative measures may cost. A 250-kW grid connected PV system and its harmonic effects compared to IEEE 519's limits is investigated in [7]. The specific results of this study concluded that harmonic distortion was highest when cloud cover was highest, and that longer distribution lines increased voltage THD. Another practical study in [8] simulated a Dutch residential distribution feeder with over 50% PV penetration. The study concluded that a certain inverter model implemented on a feeder may perform well under normal operating conditions, but severe harmonic content could cause the inverters to trip offline. This harmonic content may already be present on some distribution lines and could make PV installations behave poorly.

Power quality, specifically relating to the ratio of real to reactive power, can also be affected by PV generation. As residential power inverters for PV systems output at unity power factor, a large PV system can eliminate the need for real power delivery to a customer. When PV penetration is high on a distribution feeder, this results in a dramatically lower power factor. A study in [9] details this effect, simulating a distribution feeder with substantial PV penetration and finding the power factor of the feeder to drop to as low as 0.465. According to the sources of this paper, the DOE estimates that poor power quality can cause effects such as power outages, voltage fluctuations, and steady-state disturbances and could cost the U.S. economy $120 billion to $200 billion per year. Part of this effect may be minimized in the future due to updates to IEEE 1547 which state that DER's like PV installations must be able to provide reactive power support [10]. This study also discusses the issue of voltage unbalance. In a typical residential distribution feeder, each customer is connected to a single phase. When PV systems are installed, it is possible that more PV may be installed on a single phase, or that the variable nature of PV generation may cause more generation on one phase rather than others.

Another effect of PV generation is increased voltage regulator tap changes. When PV penetration is sufficiently high, the voltage at certain sections of a distribution line may rise during peak generation and cause a voltage regulator to change taps. While this behavior is normal, PV generation's inherent unreliability could cause rapid voltage swings to occur many times a day. While IEEE 1547 introduces some limitations on rapid voltage change caused by DERs, these voltage swings still necessitate many more tap changes from a voltage regulator. This will cost a utility by increasing the need for maintenance, repair, and ultimately replacement of these voltage regulators.

Protection equipment on a distribution line may also be affected by increased PV generation. In [11], these various effects are presented and studied. Effects include reduced fault current at an overcurrent relay preventing tripping during a fault, loss of coordination between protection devices, sympathetic tripping of one distribution feeder due to a fault on an adjacent feeder, and a variety of issues when considering rapid reclosing schemes due to temporary faults in the presence of high PV penetration. The author does explain that these effects are reduced when PV penetration is lower, and many have readily available solutions. One possible solution explored in [12] is alternate settings for protection devices in the presence of high PV penetration. Nevertheless, this requires utilities to dedicate resources for each distribution line where PV penetration increases.

EV Chargers on Distribution Circuits

Future EV Growth

Electric vehicles stand poised to make a dramatic impact on the transportation sector. Plug-in electric vehicles (PEVs) include both plug-in hybrid vehicles that retain some sort of internal combustion engine for battery recharging and battery electric vehicles that are powered from a battery alone. The batteries in these vehicles are DC power sources and must be charged using appropriate voltage levels. Charging equipment generally consists of an active converter regulating a DC bus voltage at a certain level to properly charge the battery. The charging power for equipment varies by vehicle, but in general there are two main types of chargers.

The first type of charger is contained onboard the EV. This can charge at two different levels. Level 1 charging uses a standard 120V power source, usually capable of charging around 1.8 kW due to traditional fuse boxes for 120V sources limiting current. Level 2 charging uses a 240V connection with some external protection equipment that increases the maximum power usage up to the car's internal charger rating. Typical power ratings for level 2 chargers range from 3 kW to 15 kW.

Charging power higher than 15 kW requires additional heavy equipment that would increase the weight of the vehicle and decrease range. The second type of charger, DC fast charging, uses this heavy external converter equipment that directly supplies the car with DC voltage and current to charge the battery. DC fast chargers can range from 15 kW to 240 kW, although higher power units are in test [13] [14].

Market penetration of EVs has been gradually increasing over the past 10 years. According to [15], EVs sold in 2018 accounted for slightly over 2% of vehicle sales in 2018. This estimate does not specify which vehicle segment this refers to but comparing number of EVs sold to total light study vehicles sales suggests this market share value is the share of light-duty vehicles [16]. Future estimates vary in predicted penetration, but all agree on a definite increase in EV market penetration [17] [18].

Bulk Power System Effects

Several studies have been performed to determine the effects of increased EV penetration on the grid. Naturally, from a utility perspective, it would be advantageous not to add load in the form of EV charging during peak hours of the day, but rather during valleys, especially when PV penetration causes the dramatic valley in the middle of the day. However, the Oak Ridge National Laboratory released a study that stated EV customers could choose to charge when it is convenient for them and not for the utility [13]. This study has shown that charging will mostly take at home when people return from their jobs, cause a peak in EV electric demand around 6:00 to 8:00 pm. This will continue to exacerbate the “duck curve” phenomenon previously presented.

Many studies have been performed to determine the impact of plug-in hybrid electric vehicles (PHEVs) on generation capacity. In [19], an optimized charging schedule was used for PHEVs that resulted in up to 50% penetration in a Midwestern utility’s system before PHEV load required additional generation. Other studies reviewed in [20] provided similar results, promising high possible penetration levels if PHEV charging is optimized to make use of extra generation during off-peak hours.

Most of these studies assume some level of control is given over PHEV charging in a region as whole. This may be direct control of charging equipment, or economic control in the form of time-of-use (TOU) tariffs.

Distribution Line Effects

Like PV systems, EV charging infrastructure can have localized effects on the power grid. These issues are very similar to the issues found when integrating PV systems. Harmonic content resulting from the active converters is an issue on distribution networks. Reference [21] discusses the results of an experiment to determine harmonic distortion caused by multiple electric vehicles charging simultaneously. Multiple tests were performed, measuring the THD and TDD of a single EV charging from a low state-of-charge (SOC) to full. With the charger used in testing, the study found that while THD and TDD may not exceed IEEE 519 and IEC 61000 harmonic limits, certain individual harmonics may be violation. Further testing involved combining data from multiple tests to simulate multiple vehicles charging simultaneously. As expected, TDD slightly decreased as more EV chargers increased the chances for harmonic cancellation; however, IEEE 519 harmonic current distortion levels depend on the ratio between short circuit current and load current (I_{SC}/I_L). Increased load current from more chargers resulted in a lower ratio that further lowered the maximum allowable harmonic current distortion and, since TDD did not decrease drastically from the study's results, it was concluded that many electric vehicle chargers could cause a violation if available short circuit current was not increased. Reference [22] performed similar studies and additionally measured the predicted impacts for equipment in a distribution system. The study used known relationships between THD, temperature, and lifetime of a distribution transformer, concluding that EV chargers should not produce more than around 25-30% THD as increased THD begins to drastically impact transformer lifetime.

Beyond harmonic content concerns, EV charging load behaves similarly to other types of load found on a distribution system. High penetration, while likely to increase equipment usage like voltage regulators, is no different than increasing the load on a distribution feeder. A converter-based load like an EV charger will consume very little reactive power, and protection system impacts are no different than the addition of any other type of load.

CHAPTER 3: MITIGATION STRATEGIES BY BESS

ES has been present on the U.S. electric grid since the 1930s when a power company in New Milford, Connecticut installed a 33MW pumped-hydro station [23]. The economic benefit for these types of plants usually comes from storing energy when electric demand and prices are lower and generating when demand and price rise. In a regulated environment, using energy storage plants can reduce the need for new power plants that would be used to cover peak demand and can save the utility on new plant installation costs. As presented in Chapter 2, baseload generation traditionally consists of large thermal plants that cannot quickly ramp up and down. From a bulk power system perspective, it is advantageous to shift demand such that peaks and valleys are minimized so that a larger percentage of the demand can be served from these cost-effective but slow generation sources. ES works by increasing demand during these valleys to store energy and releasing this energy during peaks to reduce their magnitude and duration.

For bulk power systems, technologies such as pumped hydro storage (PHS) and compressed air energy storage (CAES) have historically been the solution for ES. This is due to their high energy capacity, power rating, high cycling times, efficiency, and low operation and maintenance cost [24]. However, these technologies are geographically constrained and have a relatively low energy and power density compared to other ES technologies, especially electrochemical solutions like batteries. Several problems facing the grid today presented before are specific to the distribution system, and therefore have prompted utilities to investigate combatting these distributed energy problems with distributed energy storage (DES).

Battery Functions

DES aims to solve problems rising on the distribution grid; a significant part of the reason battery technology is beginning to be used is due to their functions being well adapted to the problems facing the distribution grid today at a financially realistic price. The functions below are examples of uses of BESS on a distribution grid.

Voltage Regulation

Traditionally, voltage levels on a distribution feeder have been maintained using capacitor banks for reactive power support and voltage regulators. While effective, these resources generally respond slowly compared to DG output fluctuations. The physical switching action of these devices requires constant maintenance and eventual replacement. Finally, as output changes are discrete switching events, these events tend to create transient voltage and current waveforms that could potentially damage equipment. Increased DG penetration without reactive power or voltage support further increases switching events, requiring more costly maintenance and eventual replacement of voltage regulation equipment [25].

In 2018, IEEE released an updated version of their 1547 standard. This standard includes language about the ability for DERs to provide voltage support, either via static or dynamic reactive power support or via a voltage/active power algorithm [10]. BESS's use inverters to interface with the grid and therefore can provide reactive power support using spare generation ability at little to no expense to energy stored.

Energy Arbitrage

Also referred to as time shifting, this function is the combination of demand peak shaving and demand valley filling in order to smooth the electric demand over time. In a distribution system, this would primarily be used in order to reduce loading on lines during peak loading and defer otherwise costly upgrade costs. This is the primary function of the BESS's used in chapter 5.

PV Capacity Firming

Chapter 2 described the range of impacts PV systems can have on the distribution network. The combined effect on PV systems presents bulk power system problems, but on an individual distribution feeder level, the intermittency of PV can cause its own range of problems. One use of DES aims to combat this intermittency through capacity firming. Presented in several publications, the goal of this function is to reduce dramatic power swings caused by PV intermittency, especially during peak generation hours [24] [25] [26] [27] [28]. This function directly depends on the output of a PV station, relying on intermittency detection algorithms to trigger a change in state, outputting power when PV generation suddenly dips below an expected level.

Value Proposition of BESS

Despite the powerful ability of BESS systems to solve many problems facing the grid, these systems need to provide equal or greater value to a utility company for them to be financially viable. In [26], an ES management system is developed to provide multiple functions to a distribution grid in order to increase value. Reference [29] uses only a single function of BESS, reducing renewable energy resource (RER) curtailment. In this scenario, the BESS is not able to recoup its costs from the energy that would have otherwise been curtailed from the RER devices.

Two references, [30] and [31], provide equations to calculate the value of BESS considering different types of functions. These include equations for functions such as voltage support, investment deferral, RER curtailment reduction, and energy arbitrage. Reference [30] also compares net present values (NPVs) for different energy storage technology, concluding that pumped hydro is the unbeatable source for high power, high energy capacity ES systems. For smaller applications, these value streams may make BESS integration financially viable in today's grid.

CHAPTER 4: CASE STUDY OVERVIEW

Introduction of Study

In 2019, a southeast utility funded the beginning of a project focused on determining the value proposition of using energy storage in its distribution system, especially considering the impacts of increased PV and EV penetration. The short-term goal of the project was to identify the impacts of this increased PV and EV penetration over the course of the next 5 years. BESSs would be designed to mitigate any system vulnerabilities arising from these impacts. Finally, the economic value of these BESSs would be calculated. Long term, the goal was to document this process in hopes that utilities in regulated environments might have a roadmap for determining if energy storage is the best financial decision considering the increased PV and EV penetration facing the grid today.

Feeder Overview

Four feeders were provided for study. General information about each feeder is provided below in table 4.1. One-line diagrams of each feeder follow the table in figures 4.1.

Table 4.1: Original Feeder Historical Loading Statistics

Statistic	**Feeder CN1**	**Feeder CN3**	**Feeder CN4**	**Feeder F1**
Nominal Voltage	12.5 kV	24 kV	24 kV	12.47 kV
Historic Peak	6,076 kVA	10,302 kVA	9,435 kVA	11,376 kVA
Peak Overload	37.9%	54.5%	37.8%	135.58%

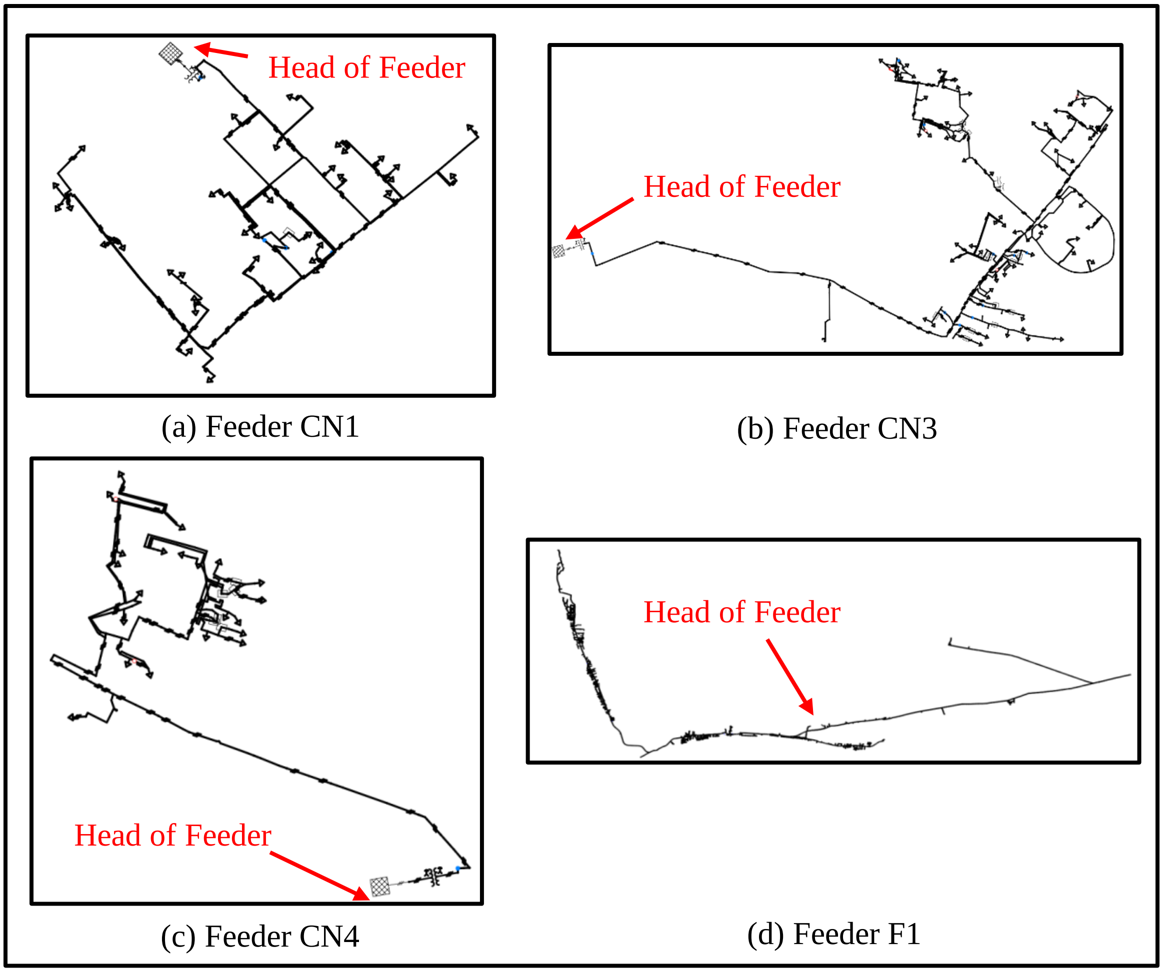

Figure 4.1: All feeder one-line diagrams with head-of-feeder locations marked.

Feeders CN1, CN3, and CN4 are located in urban areas. The load types found are generally commercial consisting of malls, grocery stores, and office buildings. The peak overload value listed is the maximum proportion of power flowing through any line on a circuit to that line's power rating. For these three feeders, the peak overload values are relatively low, indicating the distribution equipment on these lines can handle a significant increase in loading compared to their current peak loading conditions. These three feeders had the fewest issues when importing from their original CYMDIST format and were studied in detail before Feeder F1's conversion was complete. This was primarily due to their relatively low complexity. No voltage regulation equipment was found in the CYMDIST models.

Feeder F1 is located in a rural, coastal area. The load types on this feeder are almost completely residential. In addition to covering a large physical area, this feeder had several voltage regulation devices a three-phase voltage regulator, 4 single-phase voltage regulators, and 4 capacitor banks. Geographically, it is in a region well suited for increased PV penetration. During the summer months, the loading on this circuit exceeds primary ratings for many line sections and regulators. Winter months experience on average experience lower loading than a year-round populated residential feeder. For the purposes of analysis for energy storage integration, analysis of the feeder will be treated as though the residential load is more consistent, modeled after typical residential loads. Specifically, load profile data will originate from real household data from a residential neighborhood.

An infeeder element at the head of the feeder each produces all required power for the feeders. Internal impedance information from CYMDIST was initially thought to model the impedance of the rest of the grid as seen from the head of the feeder. However, these values were found to be the impedance values for the head of feeder transformers. Although it was confirmed the taps on the head transformers did not have the ability to change under load, no information was provided about the voltage change per tap or the typical operating voltage. For the studies presented here, voltage at the head of the lines are set to a constant 1.03pu.

PSS SINCAL Conversion Process

Initial work on all four feeders was to convert the models from their original format in CYMDIST to PSS SINCAL format. CYME is a power system analysis software commonly used by utilities, especially for distribution system analysis. CYMDIST is the name of the distribution system tool. An import tool built into PSS SINCAL was used as opposed to manually building each circuit based on the CYMDIST file data. The import tool requires three text files to be exported from CYMDIST: equipment, load, and network files. These files contain all the necessary information to rebuild the model in PSS SINCAL including line specifications, lengths, load values, individual distribution transformer ratings, and graphical information. These files even included summer and winter ratings for each load, leading the conversion process to create two separate models for each feeder. Conversion was verified by comparing basic load flow solutions and short-circuit calculations for each feeder between the CYMDIST and SINCAL. Unfortunately, conversion tool errors required manual correction of data.

Each element in PSS SINCAL, including lines, loads, and infeeder elements, has a network level indicating what voltage it will operate at. Certain elements properly received a network level value from data in the CYMDIST files. Elements that did not prevented load flow solutions from solving.

For each load, two ratings were provided for the assumed power drawn in each season. Each load had a type specifying it as a residential, commercial, or industrial load. Additionally, each load was technically based on the combination of all customers being fed from a distribution transformer. For example, a load in feeder F1 may represent a 50-

kW transformer feeding four households. The data for power ratings for each load was occasionally zero. For loads with this rating, PSS SINCAL's conversion tool would interpret this value as an error and would instead use the transformer size included in the load data as the actual load data. A list of all loads with zero power ratings in the CYMDIST data was compiled and the power ratings for these loads in SINCAL were manually set to zero.

Some loads from the CYMDIST data included a kWh amount. This value was thought to be an estimation of the yearly energy consumption. When this value was not zero, SINCAL's conversion tool improperly used this data to set the converted load to an equivalent model that maintained a set power rating to achieve this energy consumption over the course of a year. A list of all loads with a kWh amount were compiled and the loads in SINCAL with this incorrect equivalent model were modified to have the correct model type.

Feeder F1 had an additional issue not present in the urban feeders. The data for F1 included voltage regulators. The conversion tool did not create any element in the spots where these voltage regulators were located. As a result, manual entry to each voltage regulator was required.

Specific information on values such as total taps, voltage change per tap, and control system timing were not found. Each single-phase regulator was modeled as single-winding autotransformer. The parameters of the regulators can be found in table 4.2, including voltage lower limit V_{LL} and voltage upper limit V_{UL}. Total taps and voltage per tap were taken from typical voltage regulator parameters while upper and lower voltage limits for the control system were found in the CYMDIST data. Detailed information on tap control timing was not available. Regulators were modeled to calculate and step to the appropriate tap once every 15 minutes. While this may introduce inaccuracies between modeling and actual tap behavior, comparisons using this same approach in different network conditions are relatively accurate.

Table 4.2: Voltage Regulator Parameters used in Feeder F1 Regulators

	Taps Up	**Taps Down**	**%V per tap**	**V_{LL}**	**V_{UL}**
Value	16	16	0.625	1.0458pu	1.0208pu

Conversion was validated through comparison of results of load flow solutions and short circuit calculations between the two programs. For both calculations, compared values include node voltage, line current flow, and for load flow solutions, power draw at each load. Conversion was considered complete when differences between calculated values was below 1%. Figure 4.2 below shows a graphical representation of one comparison between feeder CN1 load flow solutions.

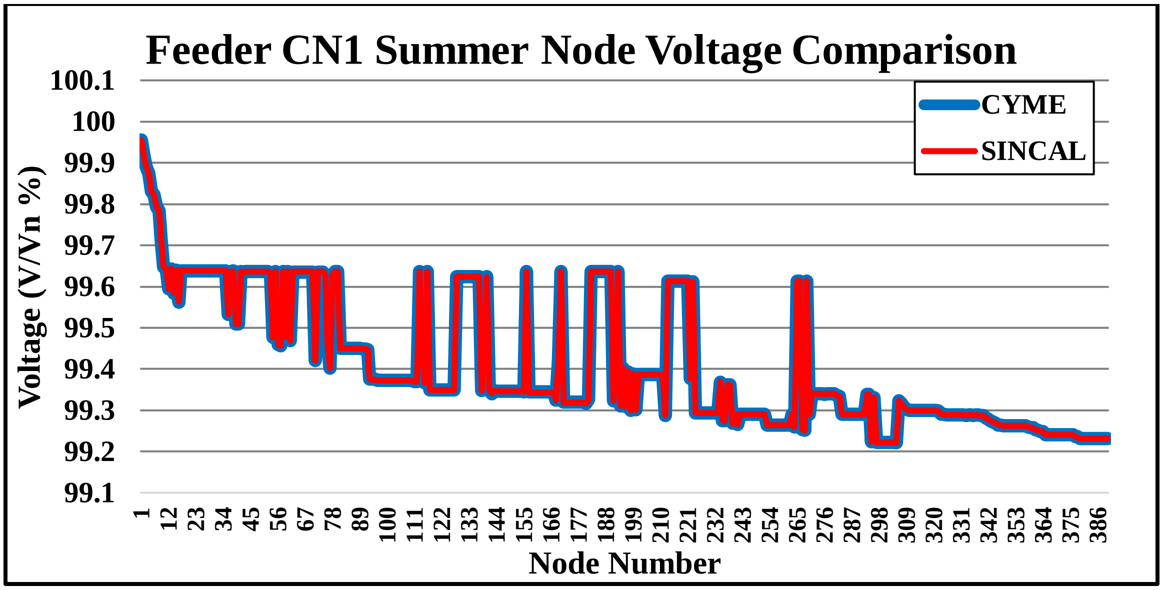

Figure 4.2: Feeder CN1 Summer Node Voltage Comparison between CYMDIST and PSS SINCAL solutions

Load Profile Generation and Validation

Quasi-static time series load flow solutions were necessary to study the effects of PV and EV penetration. Realistic load profile information was needed for each load on the feeder as advanced metering infrastructure (AMI) was not present on any load. Each load was marked by the type of load served; for example, where loads served residential households, loads were marked “residential.” The utility did provide historic chronological power flow values for the head-of-feeder transformer for feeder F1 in 15-minute increments to be used to validate generated load profiles.

Non-Residential Loads

The loads on feeders CN1, CN3, and CN4 primarily consisted of commercial loads. The Electric Power Research Institute (EPRI) has published an online database containing load profile shapes for typical building types in several U.S. cities, including the cities where these feeders are located [32]. These buildings types included gas stations, grocery stores, and office buildings. Load types to match these buildings were specified in each of the three urban feeders using satellite imaging software to view the surrounding area of each feeder. EPRI's online tool allows for a date range entry to be set before load profile data is generated. Data for each season for each load type was obtained. Data for feeder F1 was gathered as well, although this feeder had very few non-residential loads.

EPRI's tool outputted load profile data with values for average kW/ft^2 for each building type for each hour of a day. This data was normalized to the maximum value seen during the summer months. This allows each profile to be interpreted on PSS SINCAL as relative to the summer ratings provided. An example of these scaled profiles is seen in figure 4.3. Fall and winter ratings were separately taken and scaled to the winter maximum in order to allow for two season per model; spring and summer were based on the provided summer ratings while fall and winter were based on the winter ratings.

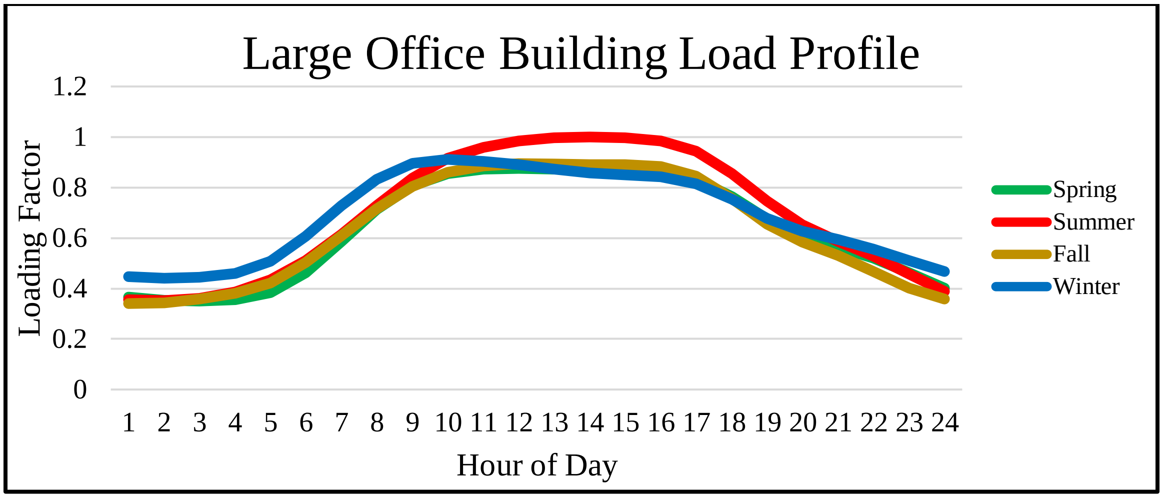

Figure 4.3: Large Office Building Load Profile from EPRI loadshape database, normalized to summer maximum

Residential Loads

Feeder F1 had a very large number of residential loads feeding traditional households. Pecan Street Inc. contains an online database with loading information on households throughout the U.S. with granularity as high as 1-minute [33]. For university researchers, data for a total of 75 households is available for free. These households are split between three cities in three states – New York, California, and Texas. As the climate in the Texan city is the most similar to the climate in the geographic area feeder F1 is located, this data was selected to be used for load profile generation. One profile of the 25 households in the Texan city contained poor data and was not used. A total of 24 profiles were used from this database.

Seasons are split since seasonal max data from the utility was provided for the summer and winter seasons. One day from each season was selected as the sample date.

Load data for each house was gathered for that date for each season. For spring and summer, every power measurement was divided by the maximum loading seen in summer; the same process was performed for fall and winter measurements relative to the winter maximum load. This produced the normalized profiles seen in figures 4.4 and 4.5. As this thesis is making estimations for future loading conditions, each data point of each load profile as been increased by 1% for each year of study. As the studies began in 2019 and forecasts are made until 2025, each datapoint has been multiplied by 1.06152. This explains why the Summer R1 profile in figure 4.4 rises above 1.0, even though the profiles are initially normalized to this value.

Dramatically reduced loading occurs during the sampled spring date for the home in figure 4.4 than during the sampled summer date. This occurs because of methodology behind date selection: extreme conditions were selected to maximize effects due to PV and EV penetration so that simulations could properly validate planning assumptions. A light loaded spring day is more susceptible to issues such as backfeed from high PV penetration while a heavy loaded summer day helps to better identify issues from high EV penetration. Fall profiles for the Texan houses were relatively high throughout the entire season; the average of the winter peaks was lower than the average of the fall peaks.

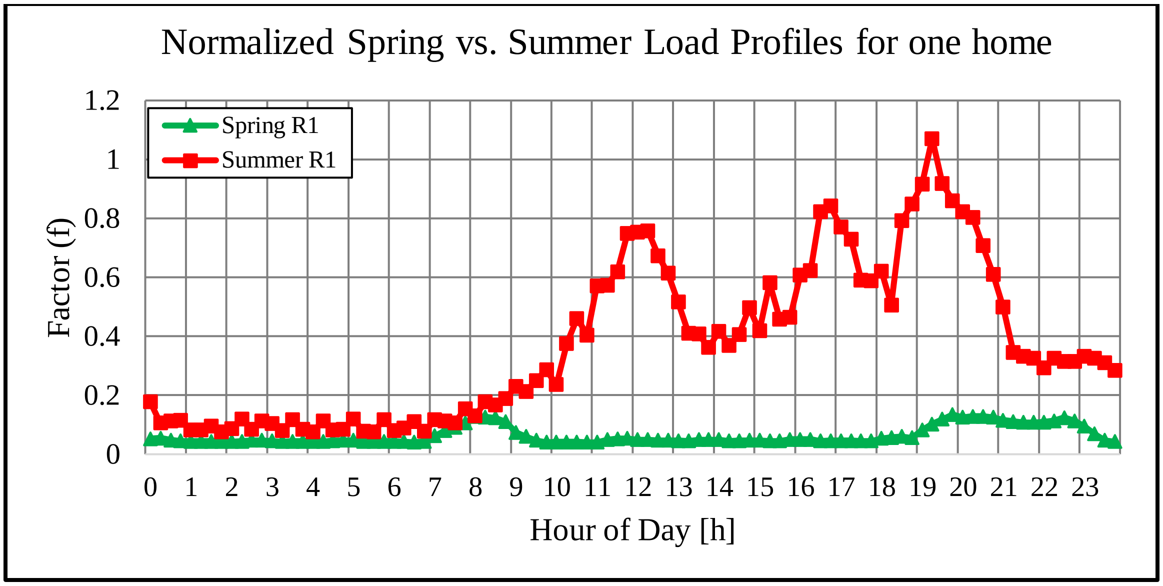

Figure 4.4: Normalized Spring vs. Summer Load Profiles for one example home with 1% yearly growth included

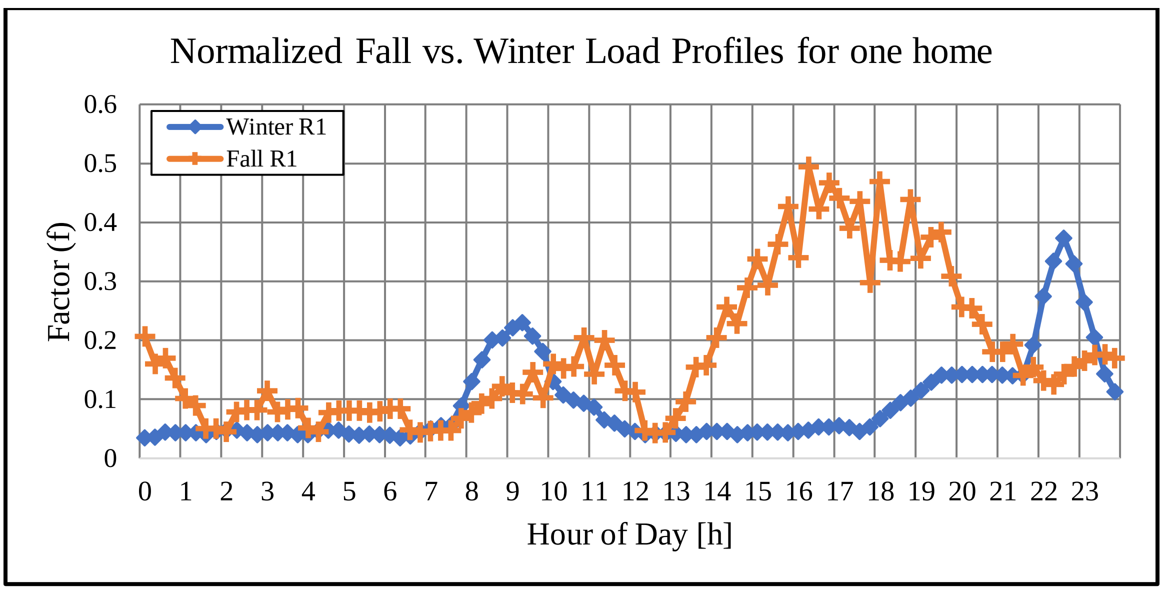

Figure 4.5: Normalized Fall vs. Winter Load Profiles for one example home with 1% yearly growth included

One observed inaccuracy due to this method of load profile generation was that dramatic swings in electric demand occurred due to the use of 24 different profiles for about 780 loads serving nearly three times as many actual houses. Therefore, each household load profile was filtered using a four-point average method to reduce dramatic swings. This more closely modeled each profile to the normalized sum of multiple houses rather than that of a single house.

With around 780 residential loads and 24 normalized profiles, approximately every 33 loads had the same profile. Once these profiles were applied in PSS SINCAL, the simulated summer peak demand was compared to the measured peak demand. As the simulated demand was lower still, a load factor was applied to every load to ensure the simulated peak matched the recorded peak demand. The resulting power flow at the feeder head transformer is shown in figure 4.6. Similarly, figure 4.7 displays feeder head transformer power flow for the simulated spring profile. Note that “SOURCE_N556” refers to the infeeder element name from the CYMDIST data. The spring, fall, and winter peaks already closely matched historical data from the utility; no load factor was applied to any load.

The load profile at the head of the feeder does not exactly match the historical data by the utility. Figure 4.8 shows the historical peak loading condition from data provided by the utility. Around 6:00, the simulation data in figure 4.6 dips lower than the historical data in figure 4.8 shows. The reason for this limitation was because the individual load profiles originated from houses in a different geographical region. The efforts for this thesis are the extent of the possibilities without having load data from customers in the same geographic area as the studied feeder. This modeling of load shapes is key to the energy storage integration process, and although the specific data here may not be the most accurate data possible, the most accurate data available was used. This is an important piece of energy storage integration.

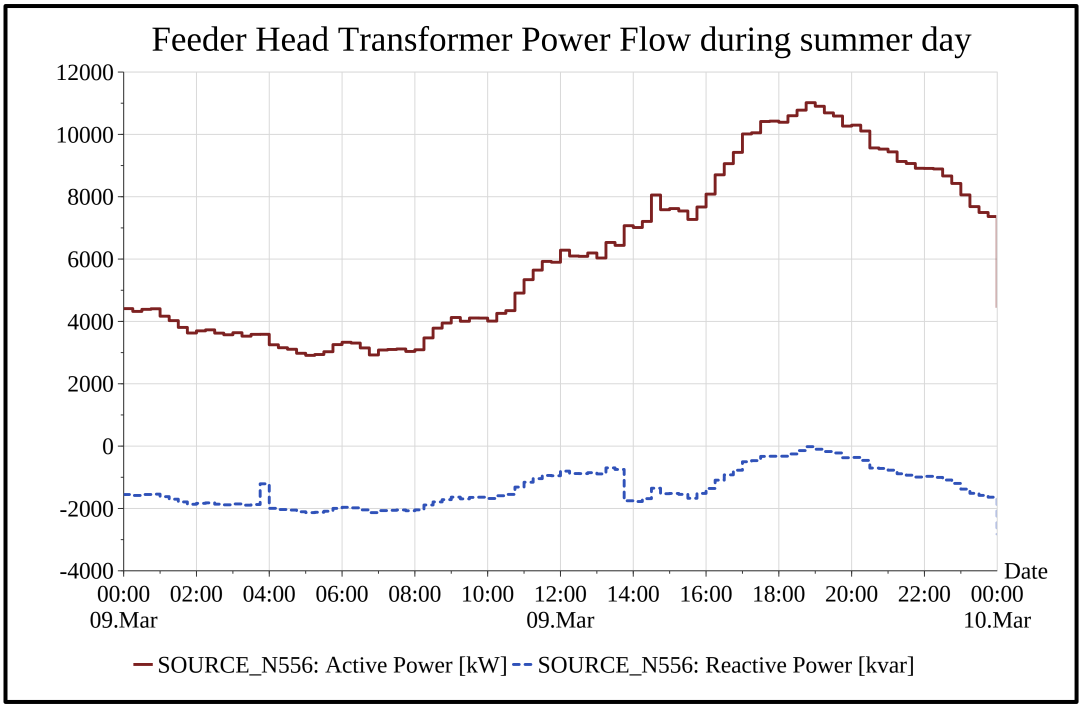

Figure 4.6: Summer Feeder Head Transformer Power Flow for Feeder F1 after smoothed load profiles were applied in PSS SINCAL

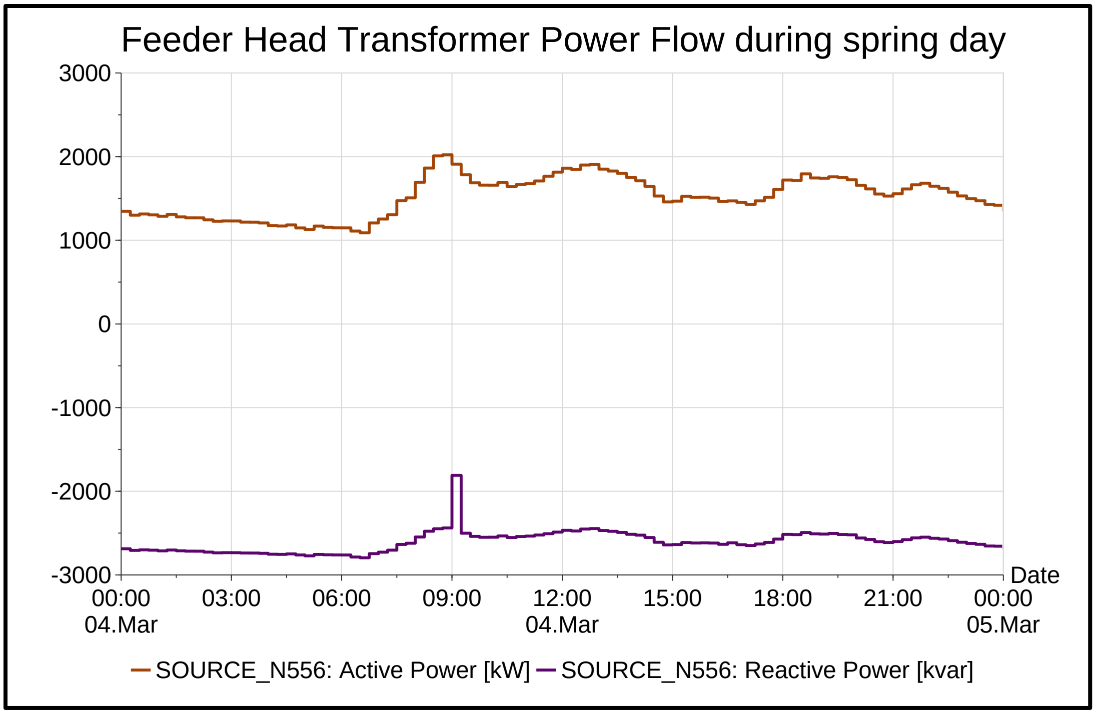

Figure 4.7: Spring Feeder Head Transformer Power Flow for Feeder F1 after smoothed load profiles were applied in PSS SINCAL

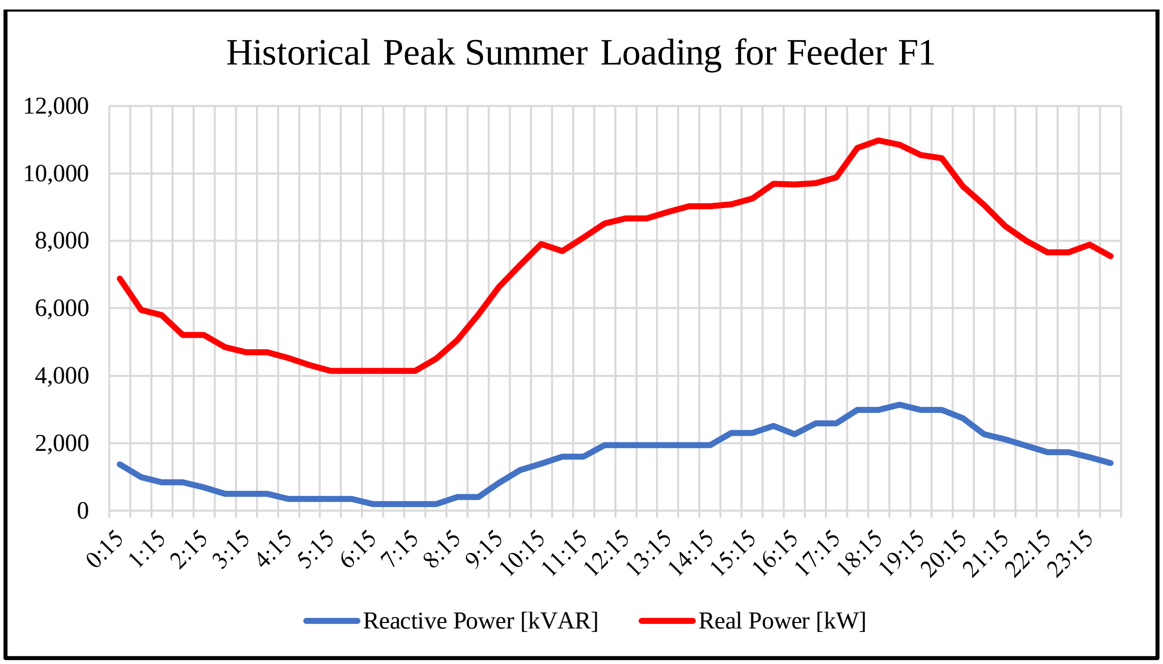

Figure 4.8: Historical Peak Summer Loading at feeder head of Feeder F1 from data provided by Duke Energy.

PSS SINCAL Excel Import Tool

PSS SINCAL offers the ability to import certain elements and model information from Microsoft Excel via an import tool. Although the tool was initially only used for load profile imports, it can be used to import a variety of elements into a network. Figure 4.9 shows the interface screen with examples of the equipment that can be imported. Imported data can either be new data added to the model, or modification of existing data. For load profile information, an initial import created load profile tags in the model data. A subsequent import added chronological factor data by referencing these tags.

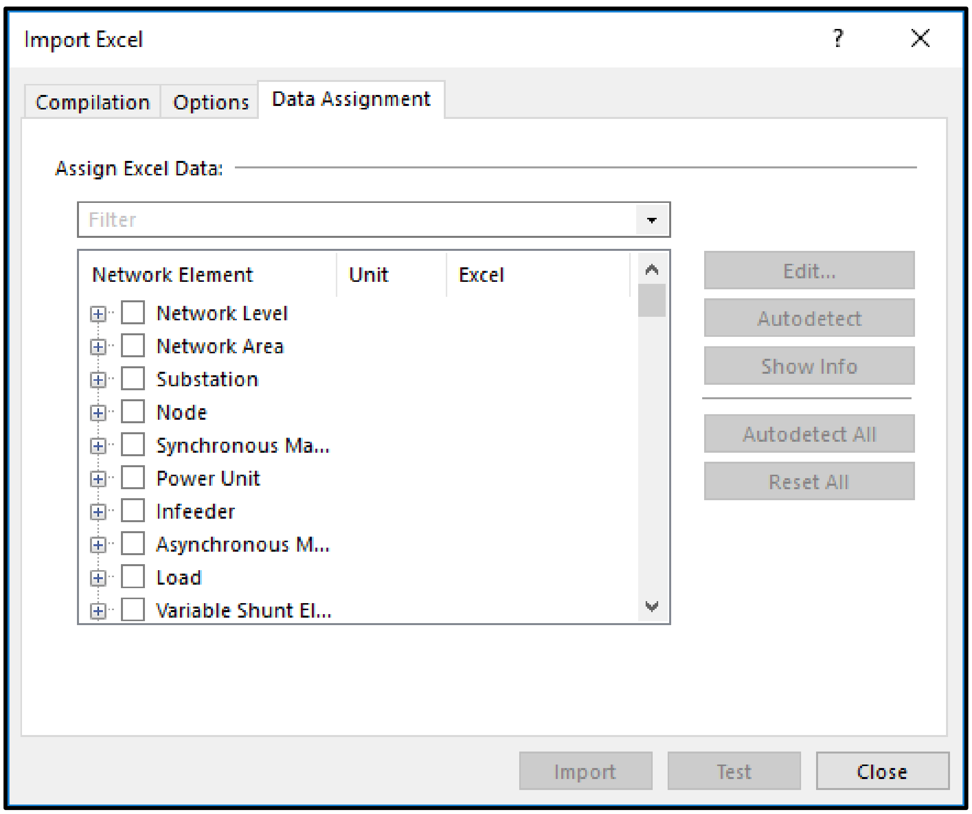

Figure 4.9: PSS SINCAL Excel Import Interface with examples of equipment data available for import

PV System Forecast

Urban Feeder Forecast

Distribution level PV systems are difficult to estimate. This is largely due to their typical behind-the-meter installation and the lack of AMI to identify changes in load behavior that could signal the presence of a PV system. As a result, estimates for future PV installations are also difficult to determine. For feeders CN1, CN3, and CN4 specifically, it was desired to find a worst-case scenario for PV installations to determine what vulnerabilities might be seen, even if the actual vulnerabilities were not as severe as in this worst-case scenario.

Available rooftop space on large buildings near each feeder were calculated using satellite mapping software. The available space was reduced by a factor of 30% to account for unusable roof space in the form of HVAC units, uneven roof, or possible poor structural support. Remaining space divided by the size of an average commercially available solar panel [34] to find the number of modules for each installation and an estimated DC size. The cumulative results are located below in table 4.3. Note that penetration here is defined as the nameplate generating capacity of all PV installations on a circuit divided by the peak load of the feeder from the provided feeder models.

Table 4.3: Urban Feeder Cumulative PV Installation Size and Penetration

	Feeder CN1	**Feeder CN3**	**Feeder CN4**
Added Solar	225 kW	2,330 kW	9,750 kW
Penetration	3.7%	22.4%	88.4%
Max ΔV	0.054%	0.22%	1.002%

To verify these installations are realistically possible, compliance with IEEE 1547's Rapid Voltage Change Criterion was tested [10]. This standard states that no DER may cause a voltage change greater than 3% of the nominal voltage over a period of one second at its point of common coupling (PCC). For each feeder model and season, load flow calculations with PV installations operating at maximum power and with PV installations generating no power were performed. The voltage at every node was compared between these load flow calculations to find which node voltage changed the most and by what amount. The results are found in the bottom of table 4.3. Clearly, although the penetration values on each feeder are very high, the installations do not violate IEEE 1547.

Feeder F1 Forecast

Feeder F1 contains mostly residential loads. Using NREL's estimates on average PV generation as a percentage of total net generation in certain U.S. states from page 26 of [4], two penetration levels are considered for this feeder: 15% and 40%. These estimates are also loosely based on annual installation growth estimates from page 37 of [4]. The first penetration level represents a more realistic expectation for PV deployment in several states in the country. In this feeder, 15% penetration results in each residential load containing about 1.5 kW of nominal PV capacity. From comparing satellite imaging to the geographic feeder model, an average of about four homes are connected to each of the 777 residential loads for a total of around 3,100 houses. Using this information, table 4.4 shows an estimate of households with a typical PV installation in this scenario. Data on a second penetration level, representing a "worst-case scenario," is also presented. This penetration results in significant backfeed at the feeder head during light loading conditions.

Table 4.4: Feeder F1 PV Scenario Overview

Scenario	Total Added PV	PV per household	% households with 8 kW PV
15% Penetration	1,111 kW	~0.4 kW	4.5%
40% Penetration	2,962 kW	~1.0 kW	12%

It was desired to determine if these estimates would cause system vulnerabilities by themselves, namely in the form of significant backfeed during light loading conditions on sunny days. Therefore, hosting capacity studies were performed to ensure these estimates were realistic in this sense.

PSS SINCAL Hosting Capacity Tool

A hosting capacity study determines the amount of load or generation possible at in a given location on a distribution circuit given a set of constraints. For the PV hosting capacity on Feeder F1, the constraints are shown below in table 4.5.

Table 4.5: Feeder F1 PV Hosting Capacity Constraints

	V_{min}	V_{max}	Max |S|	Power Factor
Value	0.98333pu	1.08333pu	2.0 MVA	1

The constraints above are the limits for all elements on a network. The hosting capacity tool considers adding load or generation either to all nodes on a circuit, or to marked nodes for observation. The tool also allows for results for individual nodes to be calculated, or for all selected nodes to simultaneously add the same amount of load or generation. The hosting capacity tool performs the steps set out in figure 4.10 to determine its output. Short circuit calculations and protection device coordination were not considered for this study.

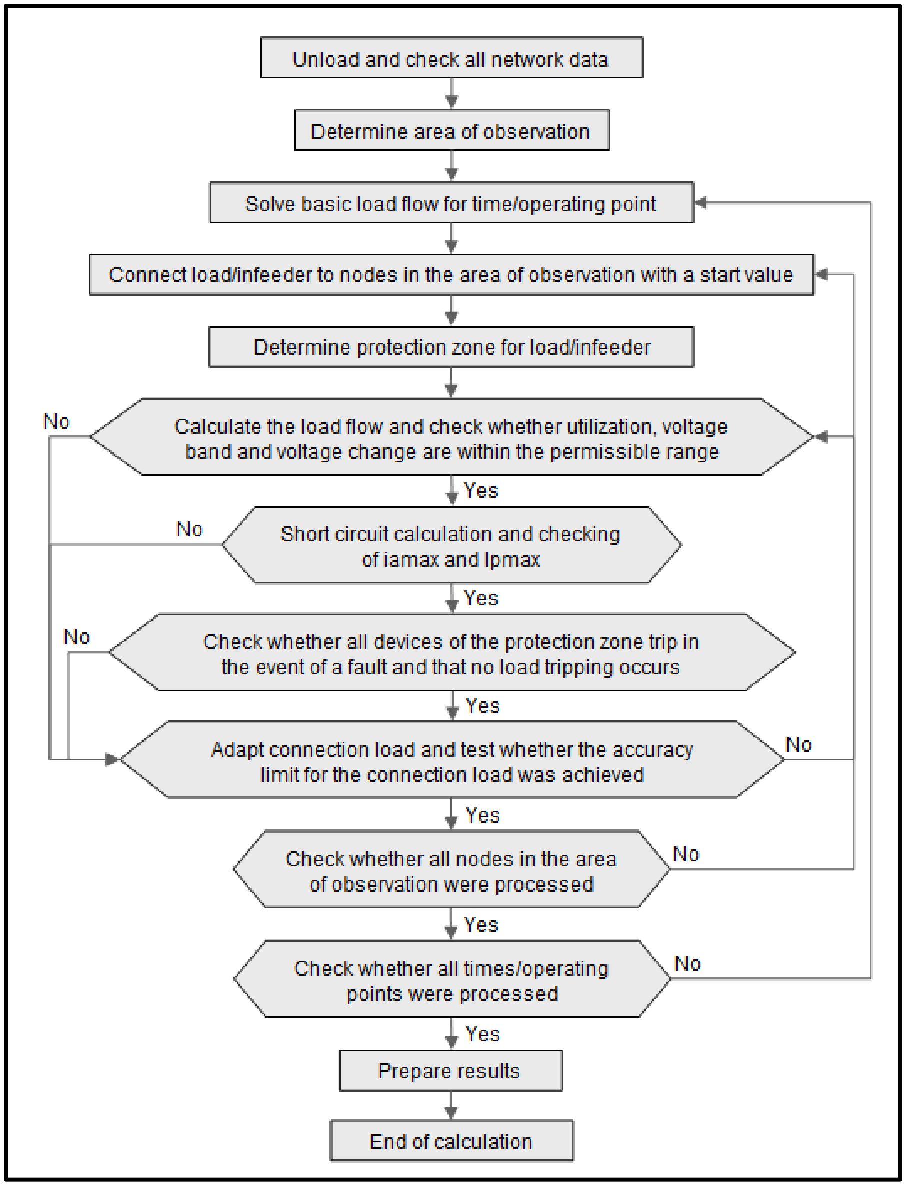

Figure 4.10: Hosting Capacity Procedure used by PSS SINCAL as defined in Siemens' documentation

For the given hosting capacity study constraints in table 4.5, voltage constraint values originate from ANSI C84.1's Range A voltage specifications [35]. The standard states that minimum and maximum voltage at the point of connection to a distribution customer be no less than 95% and no greater than 105% of the nominal rating of 120V for a standard U.S. outlet. Duke Energy uses this standard as a guideline for operation of their medium voltage lines, not necessarily maintaining the voltage on the medium-voltage lines between these exact limits. It is inferred that while voltage at certain points of the feeder may operate above or below the mentioned constraints, individual customer transformers are likely set to a tap that will adjust a typically higher or lower voltage to be within C84.1's limits. Therefore, maintaining the voltage between the limits in table 4.5 should mean C84.1's limits are maintained for each customer on the feeder. The values were chosen to be ±5% from the middle setpoint of the voltage regulator settings V_{LL} and V_{UL} in table 4.2.

The hosting capacity tool does offer a constraint on causing line thermal limit overloads. PSS SINCAL incorrectly assumes how to interpret this constraint in certain scenarios. During the hosting capacity study of feeder F1's summer model, the tool incorrectly calculated that no PV systems could be installed due to the line thermal limits being exceeded, even though PV installations would reduce this thermal limit. This may be because the hosting capacity tool does not consider current direction when overloads occur. This constraint was manually checked after running the hosting capacity module for the summer models. For other seasons, a limit of 90% was used which limited PV installation size to not cause back feed power flow to overload line thermal limits.

The apparent power parameter was set to be very large to allow PSS SINCAL to consider max penetration with essentially no limit on individual installation size. As distribution PV inverters normally output real power only, no reactive power support was considered for the hosting capacity study. A higher hosting capacity may be achieved with reactive power support.

The results of the hosting capacity study for each season are displayed in table 4.6. Penetration values are far higher than the two scenarios selected. It is noted that these results consider perfectly even spread of PV systems throughout the feeder. Heavier penetration towards one part of the feeder versus another could cause more localized violations. The results of this study verify that the proposed penetration levels for study are within realistic expectations for feeder F1.

Table 4.6: Feeder F1 Hosting Capacity Results per node

	Spring	**Summer**	**Fall**	**Winter**
PV Size per node	8.8 kW	11.9 kW	10.3 kW	9.8 kW
Penetration	60.1%	81.3%	70.4%	66.9%

PV Generation Profiles

Data from a PV installation owned by the utility was available. This data included two weeks of daily profiles in June. This data was located in a very similar geographic area to the areas where feeders CN1, CN3, and CN4 are located. The National Renewable Energy Laboratory’s PVWatts online tool was used to scale the data by season [36]. An 8-kW system was simulated using PVWatts. Hourly generation values of the system given a range of input data over the course of entire year was available for download. This input data includes irradiance, ambient temperature, and cell temperature which affect both the DC and AC system outputs. This input data is based on historic measurements from the geographic area of the feeders.

To scale the real measurement data from Duke's actual installation, the average AC output of the sample system from PVWatts was taken for each season. Normalizing the overall average of each season to the summer overall average provided scaling factors by which the utility data was modified to create approximate profiles for the rest of the seasons. These values are in the primary factor row of table 4.7.

As feeder F1 was located in a significantly different geographic area, a secondary set of scaling factors was necessary to adapt the data to represent likely PV generation profiles for the geographic area of the feeder. Another 8-kW system was simulated in feeder F1's geographic area using PVWatts. The seasonal average values were created for this simulated installation as well. Then the primary factors from table 4.7 were divided by these new seasonal average values to create the secondary factor to apply to the PV measurement data so the PV generation values better matched actual possible PV generation values for installations in feeder F1's geographic area.

Table 4.7: Feeder F1 PV Profile Scaling Factors by season

Season	Spring	Summer	Fall	Winter
Primary Factor	0.987	1.000	0.809	0.685
Secondary Factor	1.022	1.034	1.099	1.001

The specific dates from PV measurement data were based on a worst-case scenario strategy. Two dates were identified as most probable to cause severe problems on the feeder: a sunny day with constant, high PV generation and a cloudy day with intermittent PV generation. The sunny day is most likely to cause significant back feed on a distribution system while a cloudy day causes many rapid voltage changes, adding additional stress to the voltage regulation equipment. Figure 4.11 compares the measurement data of the two selected days. The inverter used for Duke's installation clearly does not attempt to generate or absorb any meaningful amount of reactive power; it is for this reason reactive power support is not considered for any PV installation in this study.

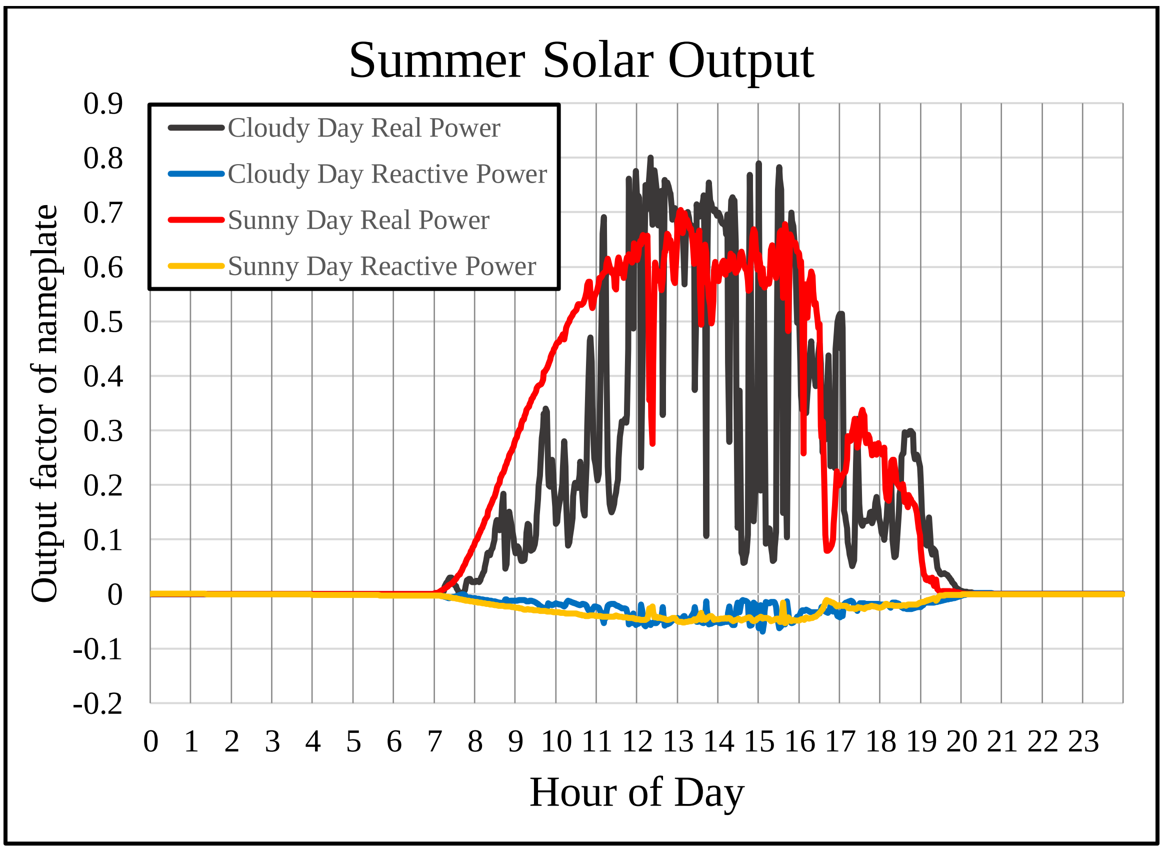

Figure 4.11: Comparison of Summer Solar Generation data for two selected days from Duke Energy installation data

EV Infrastructure Forecast

The approach for the urban feeders took a different turn when EV infrastructure forecasts were made. These forecasts were the last work completed on these feeders as the results produced results that invalidated any sort of value a battery energy storage system could provide for these feeders. The process for the urban feeders is considered separately here from the process for EV forecasting on feeder F1.

Urban Feeder Forecast

Predicting EV infrastructure growth is a very difficult task due to unreported expansion of infrastructure equipment and varying installation locations. Additionally, because overload values for the urban feeders was very low, it was determined that the remaining hosting capacity on these feeders may be large enough to power a large amount of EV infrastructure. For this reason, hosting capacity studies on each feeder were performed for all four seasons. The studies considered adding an equivalent amount of load to all existing nodes with loads present on them already as EV infrastructure equipment is very likely to be located physically near exiting office and retail establishments. The constraints of these studies can be found in table 4.8 and the results in table 4.9 below.

Table 4.8: Urban Feeder EV Hosting Capacity Constraints

	V_{min}	V_{max}	ΔV	I_{th}
Value	0.95 pu	1.05 pu	3.0%	90%

Table 4.9: Urban Feeder EV Hosting Capacity Cumulative Results

	Feeder CN1	Feeder CN3	Feeder CN4
Forecasted Max Load	6.1 MVA	7.1 MVA	11.4 MVA
Hosting Capacity	6.5 MW	7.1 MW	7.3 MW
Percentage Max Load Change	101%	69%	59%
DC Fast Chargers	43	47	48
Level 2 Chargers	811	891	915

The results of the studies show a very large hosting capacity for each feeder. For the DC fast charger value, this shows the number of DC fast charging stalls considering a size of 150 kW for each DC fast charger. For reference, one of the largest DC fast charging "stations" is a Tesla Supercharger station with 40 stalls capable of producing 120 kW each [37]. One of each of these stations could be installed on each feeder, and with all stalls occupied simultaneously, no distribution equipment for these feeders would exceed its ratings. In addition, the geographic area of this feeder is not known to have a particularly large concentration of EV ownership.

Feeder F1 Forecast

For this feeder, many of the loads are residential. Two penetration levels are considered for EV forecasts. The first penetration level considers a low-ball estimation where approximately 10% of residential loads contain a single level 2 EV charger and one single 50-kW DC fast charger is located at a small retail load. This scenario simulates the possibility of around 2.5% of U.S. homes having a single EV by the year 2025, a realistic scenario considering around 2% of all vehicles sold in the U.S. in 2018 were plug-in electric vehicles [15]. A second penetration considers a more aggressive adoption of EVs, doubling each statistic. The breakdown of EV infrastructure can be found in table 4.10.

Table 4.10: Feeder F1 EV Charging Infrastructure Scenarios

	10% Penetration	**20% Penetration**
Level 2 Power	7.6 kW	7.6 kW
Level 2 Chargers	78	156
DC Charger Power	50 kW	50 kW
DC Fast Chargers	1	2
Cumulative Added Load	642.8 kW	1,285.6 kW

EV Load Profile Generation

It is expected that most EV charging will take place at home during the evening after people return from their jobs [13]. For this reason, the generated EV profiles for the feeder include start times ranging from 6:00 pm to 6:45 pm. Charging time calculations will vary for each charging session based average miles driven per day by U.S. drivers and average efficiency of the vehicle [38]. Table 4.11 presents the values used, resulting in an estimation of a little over an hour.

Table 4.11: EV Charging Time Calculation for Charging Profiles

	Value
Miles driven per day	29.2
Average consumption of top 5 vehicles	0.303 kWh/mi
Level 2 charging time	1.16 hrs.

Once again, these profiles were generated using a worst-case scenario strategy. This strategy assumes that all chargers will be used every day at the times specified. It is possible not every charger will be used each day, or that each charger will be used at the time and for the duration assumed in this study. This study also does not consider the reduced charger power draw at the end of a charging session. These considerations were made for simplicity and for assuming the absolute worst-case scenario for sizing any BESS's. The resulting load profiles are shown in figure 4.12. Note that these profiles are only used for household EV chargers. The DC fast chargers installed do not have a load profile assigned, operating at rated power at all times. This strategy simplified analysis of energy storage power rating sizing while only slightly affecting energy capacity calculation.

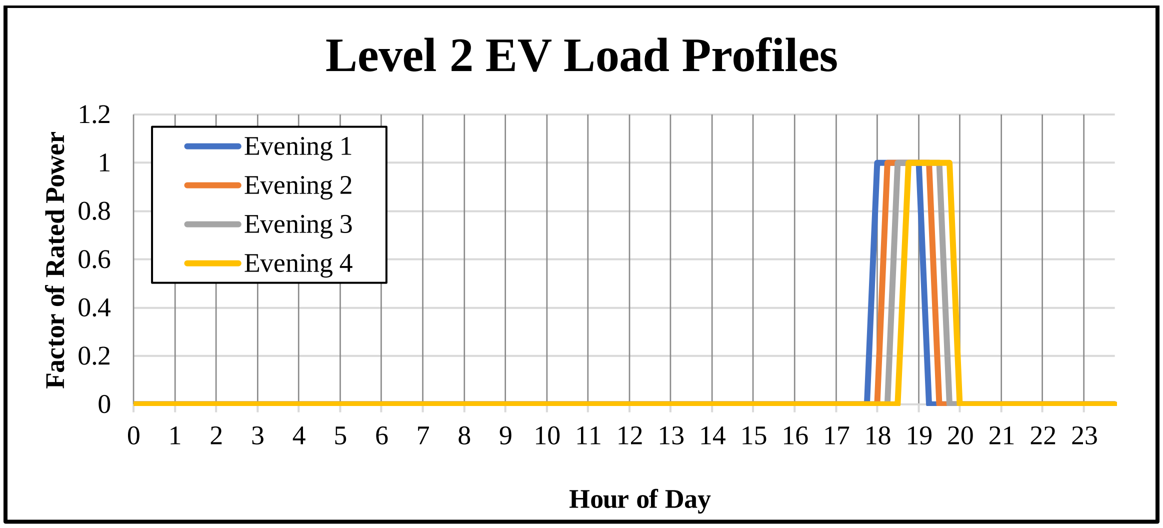

Figure 4.12: EV Load Profiles randomly applied to EV infrastructure installations

BESS Model

A standard sample model included in the PSS SINCAL platform was adapted for each BESS. This model controls power output depending on the current flowing through a specified branch, normalized to set maximum current. Monitored branches are part of the main branch of the feeder; lower current values indicate a lower loading condition on the feeder, and thus the controller commands the battery to charge. Depending on the level on loading, the battery may charge at a lower rate. See figure 4.13 between 10% and 35%. When the measured current is between these percent values of the maximum current, the battery absorbs power, absorbing more when the current is closer to 0%. The annotated positions on the x-axis indicate current value in proportion to the specified maximum current in the controller settings. The controller performs calculations for each phase individually, although an individual maximum current value cannot be set for each phase. These specific values come from the sample model included in the PSS SINCAL platform; specific values used in the case study will be presented in chapter 5.

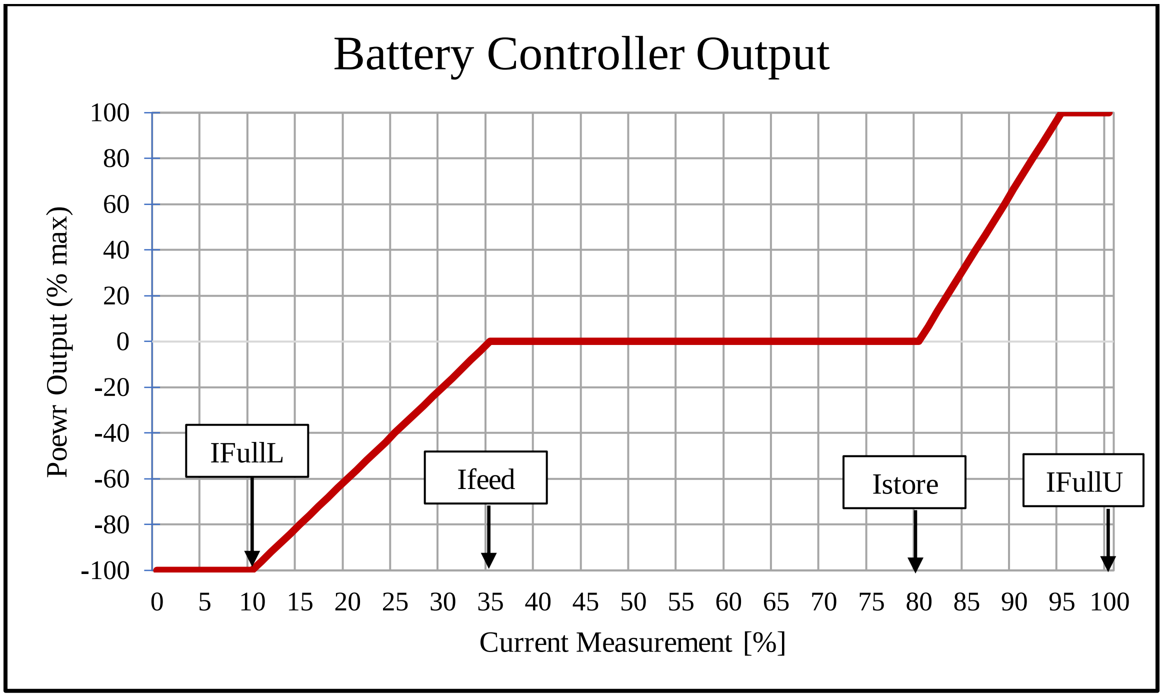

Figure 4.13: Battery Controller Output, based on remote branch loading, used for all BESS installed on Feeder F1

PSS SINCAL Integration

A BESS in SINCAL is a DC infeeder component. This component can have a block-oriented simulation language model attached that controls the outputs of the device based on a set of inputs. The models themselves can be written as graphical block diagrams with references to input and output values, or in code format. The BESS model above takes as input a monitored branch, a current limit, and four values that trigger the BESS model to start storage or start charging. Although the output of this model may set a BESS to absorb or inject power, a separate setting on the DC infeeder component limits this ability based on the stored energy in the BESS and minimum and maximum storage amounts. If this energy capacity value is not set, the component assumes infinite power.

Other adjustable statistics for a DC infeeder component include data on a connection transformer, short circuit capability, and a simplified control system for active and reactive power control based on node voltage. For the integration of the BESS models for this thesis, the branch current based control system was used as it was the simplest for the application of energy arbitrage.

CHAPTER 5: RESULTS AND DISCUSSION

The results discussed here are separated between the results of the urban feeders and the results of feeder F1. The results of the forecasting studies for feeder F1 showed significant system vulnerabilities, both present and in the future. BESS's are designed in this chapter and the value propositions are discusses.

Urban Feeders

The results of the hosting capacity studies for EV infrastructure on the urban feeders showed are larger than realistic estimates for EV infrastructure for the geographic area they are located in. The hosting capacity of each line was limited by the thermal rating of the lines located there, and since the study limited overloading to 90%, further EV infrastructure could be added beyond the capacity presented before line ratings would be exceeded. Additionally, as voltage values did not exceed ANSI C84.1's limits, it is highly unlikely that added EV infrastructure could cause voltage violations on these lines before the thermal capacity of some line section is exceeded.

- As far as value proposition of a BESS on these lines is concerned, the primary value for a BESS in a regulated environment would come from upgrade deferral. As no equipment will need upgrades in the five years the study considers, this revenue stream would not create any value proposition for BESS's. It is for this reason that BESS installations on these feeders are not considered.

Feeder F1

For feeder F1, results of the forecasting studies show significant system vulnerabilities. For the purposes of this these, the value proposition of a battery by performing energy arbitrage is considered. To determine the value proposition, a comparison between the cost of the alternative solution – in this case, upgrading distribution equipment to eliminate overloading conditions – is considered. This required a set of violation studies to calculate the exact upgrade requirements for the most limiting scenario. Times series power flow studies were performed for each season – spring, summer, fall, and winter – each solar day – cloudy and sunny – each PV penetration scenario – 15% and 40% - and each EV scenario – light and heavy. This resulted in a total of 32 variations of feeder conditions. The first set of studies, overload studies, determined where voltage and line thermal limit violations took place on each line due to the forecasted changes. This allowed the most limiting case to be identified. This case was used to size and position the BESS's.

Violation Studies

Overloading Studies

In every scenario, summer was the most limiting season. Line thermal limits were not exceeded even during low demand period like winter months when solar generation caused back feed through the head of feeder transformer. Peak demand values were slightly affected by PV penetration. Peak demand for every scenario routinely happened around hour 19:00 when PV generation was relatively little.

Table 5.1 displays an overview of the results of the studies for the summer models. The results for lines are separated from results for each regulator. Maximum overload values were initially identified using SINCAL's diagram view to identify peak loading before being accurately identified using tabular view. Regulator 1 is a three-phase regulator – due to constraints in SINCAL's diagram view, only the overall overload – the ratio of the sum of the power in all three phases to the power rating – can be identified.

Table 5.1: Overload Study Results for Feeder F1

EV Scenario	**Light**		**Heavy**	
PV Scenario	**15%**	**40%**	**15%**	**40%**
Lines				
Max Overload	151.49%	150.19%	167.51%	162.71%
Length (ft)	16,396.9	16,154.9	16,638.9	16,231.9
Current spec I_{th} (A)	400	400	400	400
Regulators				
Regulator 1				
Max overload	115.44%	112.96%	124.70%	122.22%
Power rating (MVA)	2.5	2.5	2.5	2.5
Power overload amount (MVA)	0.386	0.324	0.618	0.556
Regulator 2 (Phase A)				
Max overload	137.27%	134.50%	148.33%	145.95%
Power rating (MVA)	1.67	1.67	1.67	1.67
Power overload amount (MVA)	0.622	0.576	0.807	0.767
Regulator 2 (Phase B)				
Max overload	144.13%	141.62%	155.33%	151.38%
Power rating (MVA)	1.67	1.67	1.67	1.67
Power overload amount (MVA)	0.737	0.695	0.924	0.858
Regulator 2 (Phase C)				
Max overload	0	0	104.86%	105.19%
Power rating (MVA)	1.67	1.67	1.67	1.67
Power overload amount (MVA)	0	0	0.081	0.087

For the lines, the worst overload value is printed. The length value refers to the combined length of all lines over 100% during the worst overloading for each scenario. As expected, since heavy EV penetration adds the greatest amount of load, the largest amount of lines overloaded occurs during scenarios with this higher penetration.

The only other scenario with any overloading was the fall season with heavy EV penetration. However, the overloading for this season was not nearly as severe as the overloading for the heavy EV penetration during the summer season. The results are not displayed as they are not relevant to the energy storage system and equipment upgrade processes.

Voltage Regulator Studies

Part of studying each voltage regulator including verifying that voltage at each node did not values in an acceptable range. ANSI C84.1 was taken into consideration during the studies as well as information from the utility. According to the utility, they use C84.1's acceptable voltage ranges as a guideline for operation of their medium voltage equipment, but do not necessarily operate the equipment at these voltage levels.

As seen in table 4.2, each regulator attempts to keep voltage levels well above the lower limit of 95% in C84.1. As a result, it is likely that loads located directly after the voltage regulator may have individual transformers with taps set to slightly lower the per-unit voltage fed to the customer. Therefore, exceeding 105% on the medium voltage circuit likely still causes the customer voltage to be within C84.1's limits. During the studies, when voltages at nodes were outside C84.1's limits, the node position and violation amount were recorded. If the voltage violation was under 108% for nodes located on the secondary side of any voltage regulator, the violation was ignored. No voltage violations existed on any feeder in any scenario. Voltage rise was observed down one branch of the feeder during a study. This was with 40% PV penetration during the winter when load was very low. However, the voltage rise was not large enough to cause a voltage violation using the methodology described.

The next part of voltage regulator studies was measuring the effect on tap changes due to each scenario. Figures 5.1 to 5.5 break down the total number of tap changes for all regulators in the feeder during each scenario, comparing tap changes before and after forecasted changes were made. For figure 5.5, sunny and cloudy day values were averaged together to approximately estimate yearly tap changing events.

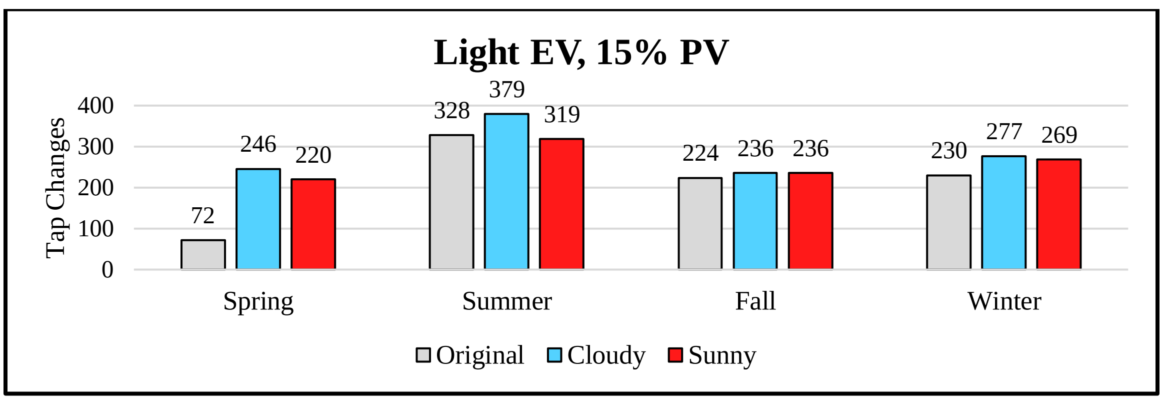

Figure 5.1: Cumulative tap changes for light EV, 15% PV scenarios for Feeder F1

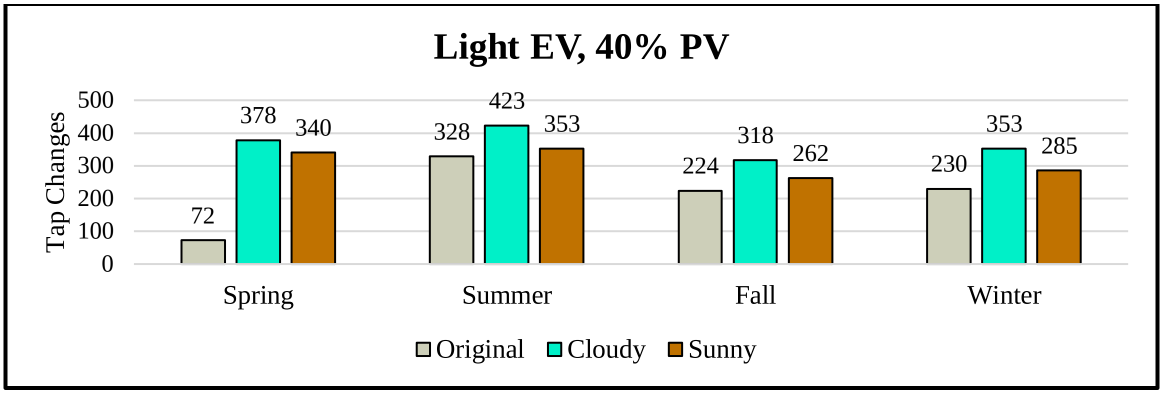

Figure 5.2: Cumulative tap changes for light EV, 40% PV scenarios for Feeder F1

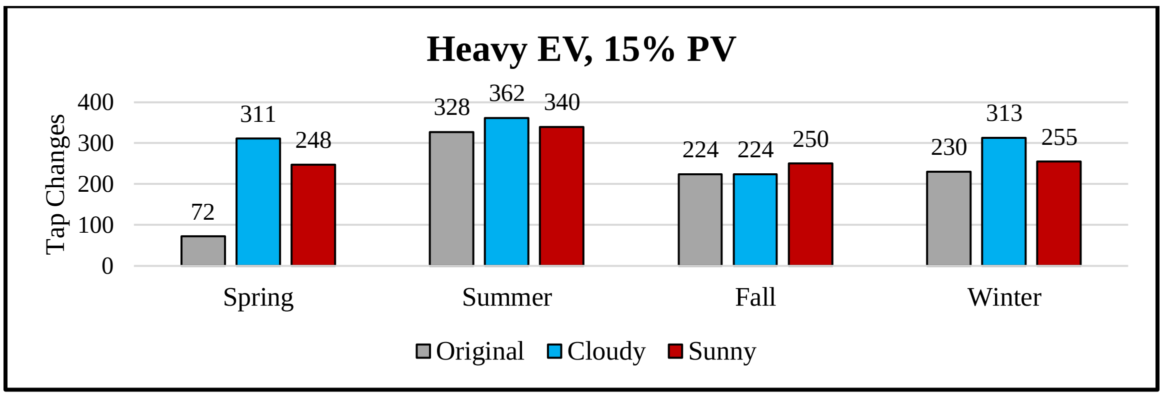

Figure 5.3: Cumulative tap changes for heavy EV, 15% PV scenarios for Feeder F1

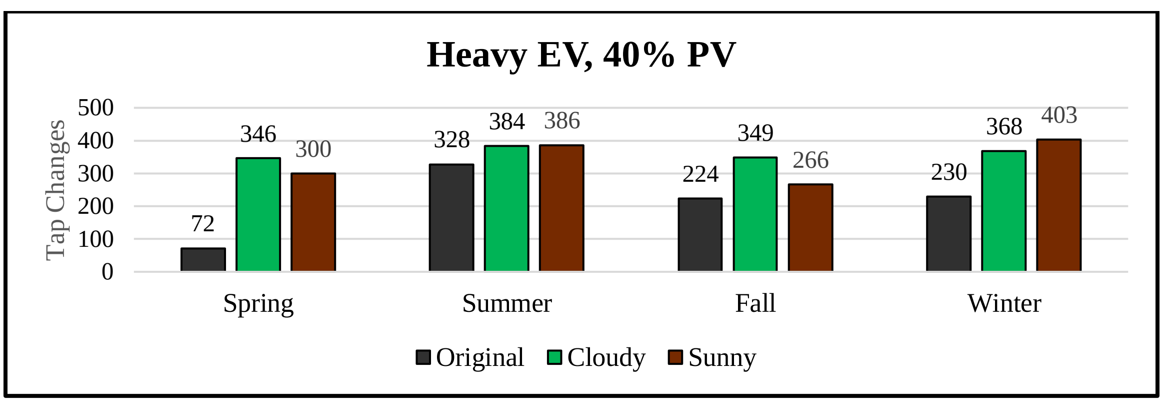

Figure 5.4: Cumulative tap changes for heavy EV, 40% PV scenarios for Feeder F1

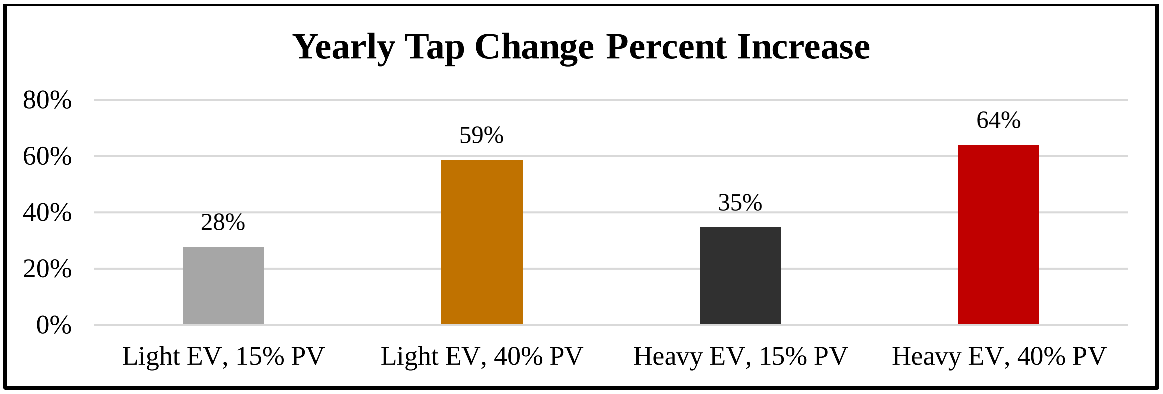

Figure 5.5: Yearly Tap Change Percent Increase Scenario Comparison for Feeder F1

Clearly, overall tap changes increase due to PV penetration. Tap changes due to EV scenario do increase when EV penetration is higher, but the rate by which tap changes increase is smaller and is not consistent with every season. This is likely because PV installations cause a greater change in electric demand than the EV scenarios as well as an intermittency causing dramatic swings in electric demand due to PV generation varying greatly.

BESS Installation

The primary function of the BESS's in this feeder is to eliminate overloading conditions and defer distribution equipment upgrades that would otherwise be necessary due to the changing load profile of the distribution system. The control system is designed to perform energy arbitrage to achieve this functionality. An important point to note is that predicted overloads only took place during summer and fall seasons. Fall season overloads were far less severe in quantity and magnitude. As a result, the BESS's will likely sit idle during the spring and winter seasons. The location and size of the BESS's are determined with the core function of deferring distribution equipment upgrades for months of overloads; therefore, only summer month overload studies were considered when determining these values.

Location

In each set of scenarios, a primary and secondary BESS were installed. This was due to the positions of the voltage regulators and the need to reduce overloading on these regulators. For the primary BESS, regulator 2 was identified as the element most downstream that experienced overloading during the worst case season model. The primary BESS location was determined to be directly downstream of this device so that it could prevent overloading by feeding power to downstream loads when current flowing through the immediate downstream branch approached the current rating of regulator 2.

After regulator 2, a second set of overloading studies were performed. The next most downstream element identified was regulator 1. It was determined a secondary BESS could be placed here to eliminate overloading on the rest of the feeder. This way, the primary BESS would not need to be sized to be so large that it might cause reverse power flow during overloading, minimizing protection equipment adjustment and replacement to accommodate this flow.

Size

The sizing of the energy storage units included determining both the power rating of the overall system and the energy storage rating. Figure 5.6 overviews the entire process in a flowchart. The process is described in detail below.

Power rating was determined first by measuring the overload value for the upstream device that each BESS was attempting to protect. The BESS's power rating (P_{BESS}) was set to provide enough power to reduce the maximum loading on the protected upstream device to below 100%. A time series power flow study was performed to confirm that the settings of the device reduced all overloading conditions to be eliminated for the protected upstream device without limit on the energy storage ability of the BESS.

Once the power rating was properly determined and the control system was verified to protect all overloads in each scenario, the total energy (E_{BESS}) required during the discharge cycles was calculated. An 80% depth of discharge was allowed for this energy capacity value. The same time series power flow study was performed to verify that E_{BESS} was sufficient. For cases where this estimate left too much charge, or depleted the BESS before the overloads were finished, E_{BESS} was adjusted, and the time series study performed again until the proper capability was achieved.

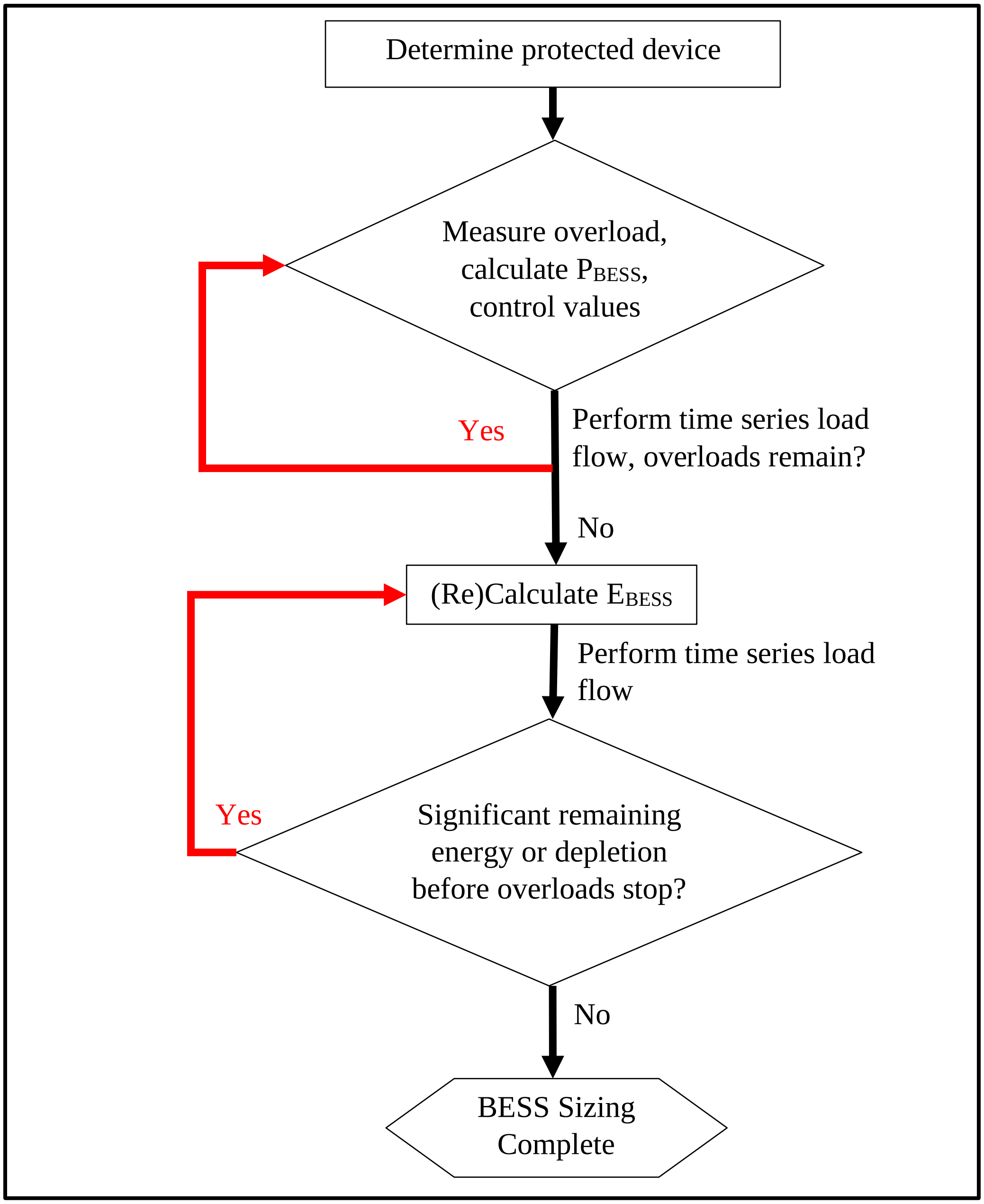

Figure 5.6: BESS Sizing Process Flowchart for installations on Feeder F1

Results

The size of each system is described below in table 5.2. The position of each system is graphically displayed in figure 5.7. The colored lines indicate equipment for which each BESS is designed to prevent overloads, the specific color corresponding to the color of text for the described BESS. From these results, it is clear high PV penetration helps reduce the total capacity required by the BESS's by reduce the amount by which lines overload during part of the days. High EV penetration increases both the power rating of each BESS and increases the energy capacity requirement.

The sizes of the BESS's here may not be commonly available from commercial BESS manufacturers. This thesis does not attempt to size the units to match what may be commercially available for simplicity's sake. These measurements are to be taken as the bare minimum requirement for this specific feeder. An analysis for another feeder may take into consideration common commercial BESS sizes, but the analysis should still follow the steps in this thesis to establish bare minimum requirements.

Table 5.2: BESS Sizes determined for Feeder F1

	Light EV		**Heavy EV**	
	15% PV	**40% PV**	**15% PV**	**40% PV**
Primary BESS				
$\mathbf{P_{BESS}}$	2.4 MW	2.4 MW	2.9 MW	2.9 MW
$\mathbf{E_{BESS}}$	6 MWh	5 MWh	8 MWh	5 MWh
Secondary BESS				
$\mathbf{P_{BESS}}$	2.4 MW	2.4 MW	2.85 MW	2.85 MW
$\mathbf{E_{BESS}}$	20 MWh	18 MWh	23.5 MWh	23 MWh

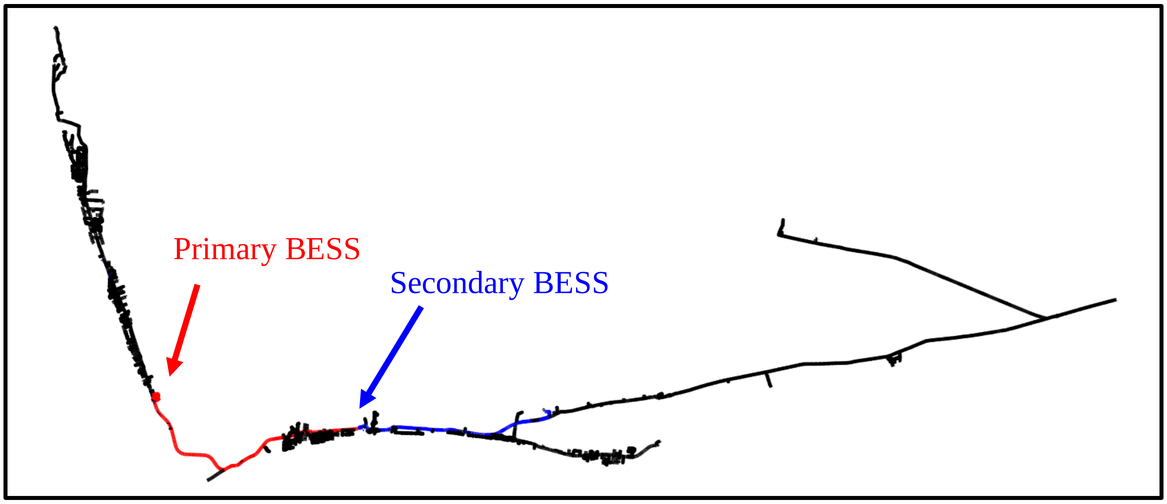

Figure 5.7: BESS Location and Protected Equipment on Feeder F1

Value Proposition

Pricing for equipment was gathered from a variety of sources in order to determine the value proposition of upgrading distribution equipment versus installing BESS's to mitigate the potential overloading.

Distribution Lines

Only sections of distribution lines that experienced an overload during the forecasted load changes were considered for replacement. In 2012, Edison Electric Institute (EEI) released a report on cost comparison between installing overhead versus underground distribution lines [39]. The estimated values included raw material costs such as line and poles and labor costs. The cost for a mile of rural distribution cable ranges from $86,700 to $903,000. Making use of this estimation, the total cost of upgrading the distribution lines in the feeder are presented below in table 5.3.

Table 5.3: Distribution Line Estimated Replacement Cost for Feeder F1

	Light EV		Heavy EV	
	15% PV	**40% PV**	**15% PV**	**40% PV**
Length of Line [ft]	16,639	16,232	16,397	16,155
Min cost per foot	$16.42	$16.42	$16.42	$16.42
Max cost per foot	$171.02	$171.02	$171.02	$171.02
Min Total Estimate	**$273,211**	**$266,528**	**$269,237**	**$265,263**
Max Total Estimate	**$2,845,580**	**$2,775,980**	**$2,804,200**	**$2,762,810**

Voltage Regulators

The National Renewable Energy Laboratory (NREL) has posted a spreadsheet containing cost estimates for a variety of distribution equipment raw material cost and installation [40]. This spreadsheet contains a cost estimate for a voltage regulator capable of 600A of current. Although the voltage level is not mentioned, this estimate is expected to be within the "ballpark" of the cost of a new regulator for the studied circuit. The estimate for replacing regulators in this specific circuit are displayed in table 5.4 below. These estimates are expected to be greater than the actual cost of replacement. This is because regulator 2 will not need as large of a regulator as the regulator from the cost estimate.

Table 5.4: Voltage Regulator Estimated Replacement Cost for Feeder F1

	Light EV		Heavy EV	
	15% PV	**40% PV**	**15% PV**	**40% PV**
Regulator 1	$650,400	$650,400	$650,400	$650,400
Regulator 2	$650,400	$650,400	$650,400	$650,400
Total Cost Estimate	$1,300,800	$1,300,800	$1,300,800	$1,300,800

BESS

A report jointly published in July 2019 by the three national laboratories provided an estimation of BESS installation costs, including capital costs for energy capacity, power conversion equipment, balance of plant equipment, construction and commissioning, and O&M costs [41]. Power conversion equipment (PCS) includes equipment such as a DC/DC converter and inverter while balance of plant equipment includes a step-up transformer and distribution wire for connection of the BESS to the feeder. The findings for lithium-ion batteries are summarized in table 5.5. Note that lithium-ion was selected here because its cost is among the lowest in the presented options in [41] along with it having the highest round-trip efficiency.

Table 5.5: Lithium-Ion BESS Estimated Costs from [41]

Parameter	Cost
Capital Cost – Energy Capacity [$/kWh]	271
Power Conversion System (PCS) [$/kW]	288
Balance of Plant (BoP) [$/kW]	100
Construction/Commissioning (C&C) [$/kW]	101

These values were then applied to the systems described in table 5.2. The results are compiled in table 5.6.

Table 5.6: BESS Estimated Total Capital Cost for Feeder F1 Installations

	Light EV		Heavy EV	
	15% PV	**40% PV**	**15% PV**	**40% PV**
Primary BESS				
Energy Capacity	$1,626,000	$1,355,000	$2,168,000	$1,355,000
PCS	$691,000	$691,000	$835,200	$835,200
BoP	$240,000	$240,000	$290,000	$290,000
C&C	$242,000	$242,000	$292,900	$292,900
Secondary BESS				
Energy Capacity	$5,420,000	$4,878,000	$6,368,500	$6,233,000
PCS	$691,000	$691,000	$777,600	$820,800
BoP	$240,000	$240,000	$270,000	$285,000
C&C	$242,000	$242,000	$272,700	$287,850
Total	**$9,392,000**	**$8,579,000**	**$11,274,900**	**$10,399,800**

Comparison

A final comparison between the cost of equipment upgrades versus the installation of BESS's is made below in table 5.7. Line costs use the worst-case cost estimate. Comparing the estimates together, equipment upgrades for this distribution feeder are significantly lower. There are other financial considerations to make when comparing the two options.

Table 5.7: Upgrade Cost Comparison between equipment upgrades and BESS installations

	Light EV		Heavy EV	
	15% PV	**40% PV**	**15% PV**	**40% PV**
Equipment Upgrades				
Lines	$2,850,000	$2,775,000	$2,800,000	$2,760,000
Regulators	$1,300,800	$1,300,800	$1,300,800	$1,300,800
Equip. Total	**$4,150,800**	**$4,075,800**	**$4,100,800**	**$4,060,800**
BESS Total	**$9,392,000**	**$8,579,000**	**$11,274,900**	**$10,399,800**

Ongoing maintenance is a cost every utility must pay with any equipment installed. The distribution line maintenance cost is expected to be very little, especially compared to maintenance of BESS conversion equipment and associated balance of plant equipment. Voltage regulator equipment maintenance will also be little, even considering the increased use due to PV and EV penetration. In this category, equipment upgrades gain a further advantage.

Loss reduction due to equipment upgrades benefits both equipment upgrades. However, loss reduction due to BESS's only occurs during times when the BESS equipment is active. Line upgrades will include reduced impedance per unit length, reducing overall losses throughout the year as opposed to only times when the BESS is active. This would be during the summer season and partially during the fall season. Equipment upgrades would be the preferable option considering this perspective.

Lastly, ongoing replacement costs could be a significant cost for both BESS's and voltage regulator. Reference [41] considers lithium-ion BESS lifetime to be around 10 years when cycled at 80% depth of discharge for 3,500 cycles. As the BESS's sized here took this DoD into consideration, and since the BESS will only be active for about half of a year (summer and fall seasons only), each BESS will likely have around a 20-year lifetime. For a voltage regulator, a lifetime of at least 30 years is estimated using reference [42]. Considering the heavy EV and 40% PV penetration scenarios, total yearly tap changes increase by around 64% from figure 5.5. This could reduce the lifetime of the units to around 18 years. However, as voltage regulation equipment is far less expensive for a complete replacement (~$1,300,000 vs. $9,000,000), equipment upgrades are more advantageous.

CHAPTER 6: CONCLUSIONS

The study presented here estimated future load profile changes due to the likely increase in PV generation in the distribution system as well as increased EV penetration in the transportation sector for a residential rural feeder. These forecasts were used to predict potential future equipment that would need to be upgraded to allow for the integration of these new resources. BESS's were installed using simulation software to determine optimal size and position to eliminate future equipment upgrades through the year 2025.

PSS SINCAL's functionalities enabled numerous studies to validate certain installations, such as hosting capacity studies to validate PV installations and import tools to convert data from other formats for use in models. The basic functions reviewed in this thesis provide useful information for studies. Numerous other functions exist in the tool that would aid in further design considerations for distributed energy resources.

The results of the value proposition analysis indicate that BESS technology needs to become far cheaper to become a financially attractive option for a vertically integrated utility to consider using it to defer distribution equipment upgrades. Even considering increased replacement cost of voltage regulation equipment, a BESS would cost considerably more for this application.

Future Studies

A large part of the reason the BESS's suggested here are not financially viable is because their energy capacity is very large due to a long period of time during which overloads occur on this distribution feeder. This directly contradicts a suggestion in reference [29] which predicts BESS's could be profitable for use in situations with large peak/low demand ratios, short period of peak demand, and small yearly increases in load. This study only considers a single distribution feeder with a large period of peak demand. In feeders with shorter peak demands, equipment upgrades must consider the peak demand; BESS's can become cheaper due to their reduced energy capacity requirement in these situations.

Harmonic distortion caused by PV inverters, EV chargers, and BESS inverters is also not considered in this study for simplicity's sake. It is likely that BESS equipment may not considerably increase THD or TDD on the distribution feeder beyond what may already be present due to higher penetration of PV and EV's; however, this study may be worth performing to determine what, if any, power quality improvement equipment may be necessary and how a BESS may affect this requirement.

This study focuses on BESS equipment on a single distribution feeder and its localized effects. A broad system study considering multiple BESS's functioning to improve localized conditions may also find additional revenue for these BESS's in the form of reduced peak loading requiring fewer generation plants to be active. Further studies would explore other revenue streams such as this reduced peak generation cost. These streams would be necessary for BESS's to become financially viable for any utility.

Lastly, this thesis focused on solely on a feeder which would need an energy storage system functioning to perform energy arbitrage to solve its specific problems. Other energy storage technologies, such as flywheels and super capacitors, may be better suited to problems on other distribution feeders. Vehicle-to-grid (V2G) technology has been introduced as a possible solution to the issues renewable energy can cause. These technologies will need to be considered in all feeders where a traditional, stationary electrochemical battery may not be the most ideal solution.

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